CA-SOP-IR-1

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 1, issue 1, paragraph 1, lines 5 through 9.

a. Please identify specific cogeneration facility examples of this type. If no such examples exist, please explain why they should not be DG facilities.

b. Later in the Companies' preliminary statement, it indicates that cogeneration should not be included because of its size. Assuming that examples as described above do exist, please elaborate by providing all reasons why cogeneration should not be considered in this proceeding.

<u>HECO Response:</u>

a. The following cogeneration facilities should not be considered as distributed generation.

HECO system: Cogeneration facilities that should not be considered as distributed generation

- AES Hawaii, Inc.
- Honolulu Program of Waste Energy Recovery (H-Power)
- Kalaeloa Partners L. P.

HELCO system: Cogeneration facilities that should not be considered as distributed generation

- Hamakua Energy Partners

MECO system: Cogeneration facilities that should not be considered as distributed generation

- Hawaiian Commercial & Sugar (HC&S)

b. The paragraph apparently referred to from the preliminary SOP is found on page 8 and states as follows: "The Companies would consider owning and operating an industrial customer-sited cogeneration facility that sells electricity and process steam to the industrial host, and delivers electricity in excess of the host's requirements to the utility. Generally, however, such a project should be considered outside the scope of this proceeding given the probable size of such a facility and the transmission of electricity from the facility to the utility's grid." The first two sentences of the response to Issue 1 (page 1, paragraph 1) supplied the basis for the Companies' position. The Companies agree with the Commission that large-scale cogeneration should not be considered in the distributed generation proceeding, but that small-scale cogeneration should. The large cogeneration projects above are significantly different from the DG technologies being considered by the Companies for customer-sited DG or CHP systems. In general, large scale cogeneration projects are like central station generation. These facilities are large sized and designed to provide significant export power to the electric grid at the transmission level, as opposed to being smaller and sized to meet individual customer loads or feed a distribution circuit. New cogeneration projects in this large-scale category would be of sufficient magnitude to require individual project or purchase power agreement applications with the PUC for review and approval. Moreover, the purpose of this project is to investigate DG, not independent power projects.

The Companies approach to customer-sited DG/CHP systems will be to size the system for customer use only, without backfeed to the utility grid.

CA-SOP-IR-2

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 1, issue 1, paragraph 2.

The Companies' identify seven criteria for a form of DG to be "feasible and viable for Hawaii." Given that the scope of the proceeding requires consideration of other items such as externalities, is it the Companies assertion that these seven criteria encompass all of the issues or do the Companies believe that other criteria may be identified for the Commission to consider in reaching its decision?

HECO Response:

The decision to install customer-sited generation will be made by customers allowing the installation of such generation. The customers making up this market will determine whether a form of DG is "feasible and viable for Hawaii", rather than the Commission. Customers may have other criteria in mind when they determine whether to install DG, and the Companies are open to the inclusion of other factors that may be considered by customers. A few customers may elect to install DG primarily based on externality considerations, rather than on the basis of quantifiable costs. The concept of "cost-effective", however, is already broad enough to take into consideration the cost of a project versus the value received (or perceived to be received) by a customer as a result of doing the project. (It should also be noted that externality considerations have already been taken into account to some extent to reduce the cost of renewable DG options through tax credits.)

CA-SOP-IR-3

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Pages 1 and 2, issue 1.

a. On pages 1 and 2, the Companies identify seven DG uses in Hawaii. Please provide a list of these DG facilities in Hawaii including ownership and operations arrangements and contractual arrangements between the facility, the utility and the customer as applicable to each facility.

b. To the extent not already discussed in Issue 2 by the Companies, please discuss other technically feasible and viable DG options that might be implemented in Hawaii but has not yet occurred.

<u>HECO Response:</u>

a. The following is a list of industrial cogeneration on Oahu:

1) Chevron U.S.A. Inc. --Owner/Operator purchase power agreement with HECO

2) Tesoro Hawaii Corporation --Operator; First Hawaiian Bank, a Trustee –Owner; Purchase power agreement with HECO

The following is a list of small scale DG units that are located on customer sites for Oahu:

1) Pohai Nani Good Samaritan Retirement Community - third party equipment
2) Hale Pauahi – third party equipment
3) Customer CHP (name is confidential) – third party
4) Fort Shafter – third party
5) Hawaii Vitrification – third party
6) Honolulu Hale – third party

There are (10) net metered customers with PV systems and (13) no-sale customers with PV systems connected to the HECO grid. These PV systems range in size from 0.3 to 50 kW.

<u>HELCO Response:</u>

HELCO owns and operates four substation-sited peaking generation units:

1) Kapua
2) Ouli
3) Panaewa
4) Punaluu

HELCO has no substation-sited generation to address a case-specific transmission problem.

The following is a list of commercial customer-sited generation for CHP systems:

1) Fairmont Orchid, third party equipment
2) Kona Community Hospital, third party equipment
3) Hilo Medical Center, third party equipment
4) Regency at Hualalai, third party equipment

The following is a list of industrial customer-sited cogeneration:

1) Mauna Loa Macadamia Nut Corporation, customer-owned and operated
2) Cyanotech Corporation, customer owned and operated

HELCO does not have a comprehensive list of all off-grid, customer-sited generation. The following is a list of known customer-sited generation, operated in parallel with the utility grid. There are (14) net metered customers with PV systems, (2) small-power purchase as-available wind energy systems, (1) small-power purchase hydro as-available energy, (5) Schedule Q wind customers, (3) Schedule Q hydro customers and (9) no-sale customers with PV systems connected to the HELCO grid.

MECO Response:

MECO does not own or operate substation-sited peaking generation units.

MECO has no substation-sited generation to address a case-specific transmission problem.

The following is a list of commercial customer-sited generation for CHP systems:

- Customer CHP (name is confidential), third party equipment
- Grand Wailea Resort, EPRI-owned, customer operated, MECO maintained

The following is a list of industrial customer-sited power only generation:

- Maui Land and Pine, customer-owned and operated

MECO does not have a comprehensive list of all off-grid, customer-sited generation. The following is a list of known customer-sited generation, operated in parallel with the utility grid. There are (13) net metered customers with PV systems and (5) no-sale customers with PV systems connected to the MECO grid.

The Companies do not have a comprehensive list of all stand-by generators on its systems.

CA-SOP-IR-4

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Pages 2 - 4, issue 1.

a. The Companies identifies various fuels that might be used by certain DG technologies, such as the ICE and microturbines. Please provide the Companies' understanding as to the fuel that is used by CHP.

b. Please provide information that includes historical (1 3 years) and projected fuel prices and the availability of each fuel that could be used by a DG application (natural gas, propane, diesel, methanol, bio-gasses and gasoline). If available, please provide this information by island. Please include a copy of any analyses, reports or studies that support the response.

HECO Response:

a. At the current time, the most viable CHP system technologies can utilize diesel fuel (including bio-diesel), propane or SNG. Hydrogen fueled systems are currently in development.

b. Natural gas, methanol and bio-gases generally are not commercially available in Hawaii. Historical and forecasted prices for synthetic natural gas ("SNG") and propane should be requested from TGC. The Companies have not tracked or forecasted gasoline prices. Historic information regarding the Companies' diesel fuel purchases has been provided in fuel filings. The Companies' forecasts of diesel fuel prices were provided in the workpapers to Exhibit H, filed November 13, 2003, in the CHP Program, Docket No. 03-0366. See page 9 for HECO, page 28 for HELCO, and page 49 for MECO.

CA-SOP-IR-5

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. pages 2 - 4, issue 1.

The Company identifies certain other practical issues for the Commission's consideration. Please provide a more detailed insight on the following:

a. Fuel type. For each applicable fuel type (e.g., propane, diesel, etc.), please identify each possible permit and the agency that evaluates and issues the applicable permit

b. Efficiency. The Companies have identified a range of thermal efficiency of fuel for CHP systems. For each applicable DG technology (cogeneration, ICE and microturbines), please provide the range of thermal efficiency. Please provide copies of the analyses performed by the Companies or identify the source of the data used to support the response.

c. Land use. In certain sections, the Companies have made references to land requirements. Please provide the following and a copy of the analysis or identify the source of the data used to support the response:

    1. The range of land requirements for each DG technology. The response should be a value of land unit over unit of power.

    2. The various land permitting requirements for each DG technology and the agencies that issue the permit.

d. Air emissions/quality. The Company has provided an abbreviated list of air emissions on page 24. Please provide the following and a copy of the analysis or identify the source of the data used to support the response:

    1. A list of particulates or pollutants emitted into the air by each DG technology. To the extent that the response varies by fuel type, but are common to each DG technology, the response may be by fuel type instead.

    2. The various air permitting requirements for each DG technology and the agencies that issue the permit.

    3. Please identify any commercially available control technologies that might mitigate air emissions issues.

e. Sound emissions/quality. Please provide the following and a copy of the analysis or identify the source of the data used to support the response:

    1. The general sound quality and/or decibel issues associated with each DG technology.

    2. The various air permitting requirements for each DG technology and the agencies that issue the permit.

3. Please identify any commercially available control technologies that might mitigate sound emissions issues.

f. Water requirements. To the extent applicable, please provide the following and a copy of the analysis or identify the source of the data used to support the response:

1. The water requirements for each applicable DG technology. In your response, please indicate whether the water requirement is limited to potable water, or whether non-potable or treated non-potable water might be used.

2. The various permitting requirements for each DG technology that requires water and the agencies that issue the permit.

g. By-products. For each applicable technology, please provide the following:

3. Please identify the by-products created by each applicable DG technology that requires disposal.

4. If applicable, please identify those by-products that require testing or other control procedures by a regulatory agency.

h. Capital costs. Please provide the estimated capital costs for each type of DG technology in a cost per power unit ratio. Please provide a copy of the analysis performed by the Companies or identify the data source used to support the response.

i. Ongoing operating and maintenance costs. Please provide the estimated ongoing O&M costs for each type of DG technology in a cost per energy unit ratio. Please provide a copy of the analysis performed by the Companies or identify the data source used to support the response.

j. The Company has identified the possible uses for certain types of DG technology (e.g., ICE has been used for emergency power, standby power, peaking, cycling, baseload and cogeneration applications). Please identify the possible uses for each DG technology (e.g., emergency, standby, reactive power, etc.).

k. Please provide the current availability and reliability metrics for each DG technology.

<u>HECO Response:</u>

The Companies have compiled a brief summary table in response to the information requested. The data is intended to be representative of the technologies but is not based on a comprehensive study and is not a definitive comparison of DG technologies.

Summary Table of DG Technologies and Requested Data:

	ICEs	CTs	Microturbines	Fuel Cells	PV	Wind
Fuel Types	Diesel Propane SNG	Diesel Propane SNG	Diesel Propane SNG	Propane SNG	n/a	n/a
Efficiency	8,955 Btu/kWh ~ 11,000 Btu/kWh 9,780 Btu/kWh	11,882 to 14,741 Btu/kWh ISO on Natural Gas	13,700 Btu/kWh 12,200 Btu/kWh			
Land Use	Low	Low	Low	Low	Medium 5 to 10 acres per MW	High 6 to 20 acres per MW
Air Emissions	NOx: 1.2 - 6.9 g/bhp-hr CO: 2.1 - 2.3 g/bhp-hr HC: 0.12 g/bhp-hr PM: 0.038 g/bhp/hr				n/a	
Noise	69 dbA at 3 meters using acoustical enclosure		65 dbA at 10 meters using acoustical enclosure		n/a	
Water	Closed Cooling Water System	Closed Cooling Water System	Air cooled		n/a	n/a
By-Products	Waste oil Waste cooling water	Waste oil Waste cooling water			n/a	n/a
Capital Costs	~ $1,000/kW for DG ~1,600/kW for CHP		~ $1,776/kW for liquid fuel in 8-unit container		$10,000 to $13,000/kW installed	$1,700 to $2,300/kW installed
O&M Costs	FOM and VOM $18 to $20 / MWh				FOM $26 to $58/kW per year VOM $0.13 to $30/MWh	FOM $80 to $270/kW per year VOM $2.60 to $5.40 /MWh
Applications	Emergency power DG/CHP applications	Emergency power DG/CHP applications	DG/CHP applications	DG/CHP applications	Daytime / as-available power	As-available power
Reliability	91%	91%	~ 80% for liquid fuels		~ 45% 24-hour day availability	~ 95% when the wind is blowing

The IR requests information about possible permits and issuing agencies for fuel type, land use, air emissions, sound, and water requirements. There are numerous construction permits, operating permits and/or environmental permits and each DG project will have project specific permit requirements based on the technology, size, fuel use, location, and other factors. In addition, the DG projects would be designed in accordance with the applicable code requirements such as the Uniform Building Code, National Electric Code, National Fire Code, Plumbing Code, etc. The following discussion provides a listing of many of the possible permit requirements but it is not a definitive list of all Federal, State and County permits.

Environmental Permits

Environmental permits and compliance requirements will vary depending on the DG technology, fuel type and site location and conditions. Possible environmental permits are listed below:

- National Pollutant Discharge Elimination System (NPDES) permits issued by DOH Clean Water Branch, including:
    - Individual facility discharge permit – for cooling water and other industrial wastewater discharges to navigable waters
    - Construction Stormwater Permit – for construction projects larger than one (1) acre.
    - Construction Dewatering Permit – for construction dewatering to storm drains, drainage ditches or other navigable waters of the State.
    - Hydrotesting water – for discharge of hydrotest water from tank integrity testing, etc.
    - Treated Process Water – for discharges of wastewater associated with well drilling activities.

- City & County of Honolulu (C&C) Individual Wastewater Discharge permit – issued by the C&C Department of Environmental Services for sanitary wastewater connections.
- C&C Storm Drain Connection Permit – issued by the C&C Department of Environmental Services for facility connections to the C&C's storm sewer system.
- Underground Injection Control (UIC) Permit – issued by DOH Safe Drinking Water Branch for wastewater discharges to underground injection wells.
- Used Oil Management Permits – issued by DOH Solid & Hazardous Waste Branch for certain used oil management activities, including: used oil generation/marketing, used oil processing used oil transporter, etc.

Other possible environmental compliance requirements include:

- Spill Prevention Control and Countermeasure Plan requirements – EPA required plan for preventing and controlling releases from aboveground storage tanks exceeding a combined capacity of 1,320 gallons.
- Underground Storage Tank registration and management requirements – DOH Solid & Hazardous Waste Branch requirements for underground storage tanks.
- Hazardous substance reporting requirements – DOH and EPA require reporting of hazardous materials that are:
    - stored at facilities in excess of threshold planning levels (i.e., Emergency Planning and Community Right to Know Tier II reporting),
    - released to the environment above Reportable Quantities (i.e., State Contingency Plan), and

- released, used and/or manufactured at the facility above threshold planning levels (i.e., Toxic Release Inventory).

o Testing of by-products (or waste products) – Other than testing/monitoring activities required by permits listed above, DOH or EPA may require testing of solid and liquid wastes to determine if they are hazardous. If tests show by-products to be hazardous, the facility must comply with hazardous waste regulatory requirements (regarding the treatment, storage and disposal of wastes). Additional biennial reporting may be needed if the facility meets the definition of a large quantity generator during any month during a reporting year.

The DG projects may require an air permit and is required for all liquid fuel DG projects. The emissions generated by the various DG technologies will vary by the technology itself, including make and model number of the prime mover, as well as the fuel type proposed. As indicated in HECO's preliminary statement of position, these emissions could include oxides of nitrogen, sulfur dioxide, particulate matter, carbon monoxide, and volatile organic compounds. If the proposed application triggers the need for an air permit, the issuing agency will be the Department of Health and possibly the Environmental Protection Agency. There are several control technologies available for each type of generating unit. These control technologies would be examined as part of the permitting review process and are dependent on the type of air permit being considered. Typical control technologies include, fuel selection, fuel injection timing, water injection, etc. Any annual emissions greater than 100 tons per year triggers a more detailed evaluation of the project emissions.

The DG projects may require a noise permit. The sound levels emanating from the DG units will vary depending on the technology under consideration as well as the make and model. If a noise permit is required, the issuing agency is the Department of Health. Control technologies available for acoustic treatment are dependent on the technology and the supplier. Sound mitigation equipment such as mufflers, baffles, insulation, etc. are often offered by suppliers. In addition, exterior sound attenuation is also available by acoustic walls, enclosures, and similar approaches.

The Companies also plan to conduct Environmental Site Assessments to satisfy property transaction due diligence requirements (i.e., to minimize the environmental liabilities that might be associated with purchasing, leasing or otherwise using contaminated properties).

The following is an example of a generating unit permit checklist with permit requirements which may or may not apply to a DG project.

Example Checklist of Potential DG Project Permit Requirements

PERMITS	FEDERAL	STATE	COUNTY
PUC Expenditure Approval		PUC	
Air Permitting (EPA if emissions greater than 100-tons)	EPA	DOH	
Non-Covered Source Permit if liquid fuel and less than 100-tons		DOH	
SMA/EA SMA Condition #21			PC
UIC-PTC PTO		DOH (SDWB)	
UIC-PTO	EPA		
CZM		CZM	
Well Construction Permit		DNLR	
Pump Installation Permit		DNLR	
NPDES Storm Water Permit		DOH	
Construction Activity		(CWB)	
NPDES Storm Water Permit Industrial Activity		DOH	
Certificate of Water Use		WRMC	
Water Use Permit		WRMC	
Parking Variance			DPWLU
Building Permits Retaining Wall Fuel Oil Containment Wall Emissions Stack Equipment Foundations Fuel Oil Storage Tank			DPWLU
HVAC		DOH	
Water Treat. & MCC Rm.			
Septic System		DOH	
Demolition of Structures		DOH	
Aboveground Tank Installation No. 2 Diesel storage tank			FD
Noise		DOH	

CA-SOP-IR-6

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 4, issue 1, paragraph 4.

a. The Companies state that wind farms “appear to be economically feasible” but later indicate that "it remains to be seen whether small, customer-sited WTG installations are economically feasible, taking into consideration costs and siting constraints.” Please explain what “remains to be seen”.

b. If available, please provide the cost per kWh for WTG with and without credits for projects (if available, one or two examples would suffice) that have been completed using the federal and state tax credits.

HECO Response:

a. In general, most commercial wind farm installations are large megawatt-sized systems where substantial numbers of wind turbines are installed. These wind farms are usually located in areas that have strong, sustainable winds. The trend for wind turbine design and size is moving towards large megawatt-sized, variable speed wind turbines with power electronics. These sophisticated wind turbines can have towers up to 150 to 180 feet and blade spans equivalent to a football field. Thus, taking advantage of economies of scale, these wind farms with large wind turbines can be economically feasible. There are only a few wind turbine manufacturers building smaller kilowatt sized units (10 to 100 kW sized wind turbines). For DG applications, smaller wind turbines may have to be used. These smaller wind turbines can be less efficient with simpler designs than the larger wind turbines. Thus, separate studies would be needed to identify the wind resource and evaluate the wind turbine performance, cost and other impacts with the customer needs. The Companies have not attempted to do any such studies.

b. HECO has not conducted cost per kWh calculations for DG applications with the smaller wind turbines at this time. In general, the federal wind production tax credit (expired in December 31, 2003) was worth about 1.5 cents per kWh.

CA-SOP-IR-7

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 6, issue 1, paragraph 1.

a. In the Companies' assessment, what size DG application would be considered to be "large enough" for a reasonable economy of scale? Please provide copies of any analyses that support the response.

b. In the Companies' assessment, what DG efficiency rating would be "highly efficient" enough to be accepted in Hawaii? Please provide copies of any analyses that support the response.

HECO Response:

a. The minimum economical size for a DG facility will depend upon the technology to be employed. For small combustion turbines, the minimum size of installation is 1.5 to 2.0 MW based upon the expected installed cost and heat rates. For internal combustion engines, the minimum size of installation would be approximately 250 to 300 KW. This is based upon a CHP configuration utilizing two small engines and giving consideration to system heat rate, reliability and O&M costs. For some renewable applications, such as PV, the size may be even smaller.

b. As stated in the Companies' preliminary SOP, CHP systems can be "highly efficient" due to their use of waste heat to displace other energy usages (for example, by driving an absorption chiller and displacing electric air conditioning).

CA-SOP-IR-8

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 8, issue 2, paragraph 5.

a. Please provide information, studies or analyses that support that such applications (customer-sited generators) could not be cost effective for the Companies.

b. If not included in your response to part a. above, please discuss whether such applications be cost effective for the customer and provide information, studies, analyses that support the response.

HECO Response:

a. The Companies' economic analysis of the proposed utility CHP Program with the efficiency benefits of using the thermal waste heat and the income stream from the customer for that captured heat results in the Companies' expectation that customer-sited generators simply for the purpose of generating electricity for the customer would not be cost-effective. There was no formal analysis concluded for the electricity alone configuration.

b. Such applications may be cost effective for a specific customer depending upon the customer's specific needs. For instance, a customer requiring extremely high reliability may be willing to pay a premium cost.

CA-SOP-IR-9

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 8, issue 2, paragraph 5.

Please explain why the Companies do not intend to engage in the business of providing off-grid generation.

HECO Response:

The Companies' focus is on energy-efficient CHP systems. The customers for CHP systems generally are connected to the grid. Their electrical loads generally exceed the capacities of the CHP systems, which are sized to meet their thermal requirements. Their supplemental and backup electricity requirements can be supplied from the grid.

Off -grid CHP systems would have to be sized based on the customers' entire electrical generation load, rather than on the size of the customers' heat loads, or the customers' supplemental and backup requirements would have to be served through additional DG. In addition, off-grid users of electricity generally are smaller, residential loads, which are not of sufficient size to warrant use of a CHP system.

CA-SOP-IR-10

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 10, issue 2, paragraph 2.

a. Please provide supporting studies, analyses and examples of independent DG/CHP projects that would not be beneficial to customers and the utility.

b. If an independent, economic bypass DG project were completed, please discuss whether it would be beneficial to the general consumers and the state, but maybe not the utility company. Please provide a copy of any analysis or study that supports the response.

<u>HECO Response:</u>

a. An example on the island of Lanai is described in MECO's Application for approval of a service contract with Castle & Cooke Resort, LLC filed September 17, 2003 in Docket No. 03-0261, and the supporting analysis is attached to the Application.

b. In the case of a bypass DG project, if the revenues lost by the utility exceed the utility's marginal costs, then neither the utility nor its other customers would "benefit". The utility would lose the difference between the lost revenues and its marginal costs in the short-term, and the utility's other customers would have to make up the difference in the longer term. If the bypass is "economic" (i.e., if the customer-sited project supplies electricity at less than the utility's marginal costs of supplying electricity to the customer), then it can be argued from an economic stand point that the result is economically efficient, and the State could benefit from such economic efficiencies. However, if the utility would have installed a CHP project at a lower cost or could have preserved some of the lost revenues by installing a CHP project (taking into account the cost of the CHP project), then the utility, the utility's other customers and the State would be better off. The analysis supporting this conclusion was done for the Companies in support of their CHP Application.

CA-SOP-IR-11

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Pages 11 – 12, issue 2.

a. Please provide information, studies and surveys that support the statement that customers are asking the utility to offer a full range of services.

b. If not readily evident in the studies or surveys provided, please identify the services that the customers are demanding.

<u>HECO Response:</u>

a. The basis for this statement is conversations with and public statements by customers. No studies or formal surveys have been done.

b. In discussions with customers, they have asked that the Companies consider providing (1) on-site electricity via CHP systems and renewable systems, (2) a wide variety of conservation measures, and (3) energy services including operations and maintenance of electrical and mechanical systems, and the sale of BTUs via chilled and hot water.

CA-SOP-IR-12

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 13, issue 3, paragraph 2, lines 3 and 4.

Why do the Companies not currently anticipate providing customer sited emergency generation service?

HECO Response:

Customer-sited emergency generation operates very few hours per year and, therefore, represents predominantly a capital cost. Utility ownership of emergency generation generally would not be cost-effective for customers, given factors such as the utility's revenue tax burden and average cost of capital, and the availability of equipment leasing and other customer financing options. The benefits of having the utility own, operate, maintain and supply fuel for the emergency generation would not be enough to make the utility-ownership option attractive to customers. See the attached table for documents related to emergency generators. For items 1. and 2., these reports were done for and are the property of DBEDT, so a request to review the reports should be made to DBEDT. For items 3. and 4., these reports can be reviewed at HECO's offices. Please contact Dan Brown of HECO's Regulatory Affairs Division at 543-4795 to arrange for review.

	Title	Author	Date of Publication
1	Generator Requirements of Essential Service Facilities not Supported by Emergency Standby	HECO & KEMA-XENERGY, INC.	Feb. 5, 2003
2	Survey of Emergency Generators at Emergency and Essential Service Locations - State of Hawaii	HECO & XENERGY, INC.	February 9, 2001
3	Impact of Interruptible & Stand-by Generation Rates	Synergic Resources Corp.	March 24, 1993
4	Commercial and Industrial Stand-By Generation and Interruptible Load	Market Research & Evaluation Division-Energy Service Department HECO	July 8, 2003

CA-SOP-IR-13

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 14, issue 3, paragraph 1, lines 1 and 2.

a. Why would the Companies not intend to offer such a service (customer-sited generation for power purposes)?

b. If not already discussed in the response to part a., please discuss whether the Companies would consider customer sited generation for power purposes if this option represented the most expeditious and perhaps less expensive alternative, all other things being held equal (e.g., safety, reliability, etc.).

<u>HECO Response:</u>

a. As stated on page 7 of the Companies' Preliminary SOP, the Companies may consider customer-sited generation operated in parallel with the utility grid if such ownership is a cost-effective utility option.

b. It is not clear what is meant by "most expeditious and perhaps less expensive alternative"? There are probably hypothetical circumstances under which the Companies would consider owning, operating and maintaining customer-sided generation for power purposes, but the Companies' focus is on providing energy-efficient CHP system. See response to CA-SOP-IR-9.

CA-SOP-IR-14

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 15, issue 3, paragraph 3.

The Companies indicate that they have not taken a position on whether third-party owned installations of CHP and DG should be regulated by the Commission due to the relatively small number of such installations.

a. Assuming that, as a result of this docket, the number of such installations increase significantly. What is the Companies' position on whether such installations should be regulated by the Commission and provide the reasons why.

b. If not already identified in the response to part a. above, please identify the changes, if any, to the existing statutes or rules that would be required to effectuate the Companies' position.

HECO Response:

a. The Companies have not formulated a position as to whether a CHP System or a distributed generator owned by third-party should be regulated by the Commission, except in the case of nonfossil-fuel generating facilities. The Companies' position with respect to nonfossil-fueled generating facilities was stated in their Motion to Intervene filed August 6, 2002 in Docket No. 02-0182 (Petition of PowerLight Corporation). According to its petition, PowerLight intended to develop a renewable (photovoltaic) power-producing facility on a utility customer's site for the purposes of selling all of the available energy from the facility to the utility customer on the customer side of the utility meter. PowerLight sought a determination that a company that sells renewable energy to a utility customer that is produced on the utility customer's property for the utility customer's on-site consumption should not be defined as a "public utility".

The holdings in cases analyzed by the Companies indicated that if an entity owns one non-fossil fuel generating facility, and sells the output of the facility to one customer located adjacent to the facility, the entity does not dedicate its facility to the public use (and become a "public utility") by virtue of such sale of power. The holdings did not indicate what the result would be if (1) the customer was not responsible for the O&M of the facility, or (2) the single facility sold electricity directly or indirectly to more than one retail customer of the public utility serving the area, or (3) the owner of the facility owned a number of similarly situated facilities, each of which sold its output to only one adjacent customer, or (4) the facility was a fossil-fuel fired generating facility. The Companies agreed that the services proposed by the PowerLight (assuming that it owned and operated only a limited number of generating facilities) would not be of "public consequence and concern" as long as each facility sold power only to one customer, each facility was located on the property of the customer to which electricity would be sold, and each facility was a nonfossil-fueled generator.

In other cases, facts and circumstances to be considered would include: (1) the nature of the industry sought to be regulated, and the existence of alternatives to the service; (2) the type of customers and the scope of the market to be served, and the effect of not regulating service providers on service providers who are regulated; (3) the use of "public" resources by the non-regulated service providers; and (4) the impact on the industry and customers of regulating or not regulating the service.

In the case of CHP systems, the Companies propose to offer such systems on a regulated basis where utility ownership of such systems is cost-effective and does not burden non-participating customers. This would provide customers of CHP systems with a regulated alternative. This would also provide a mechanism for non-participating customers of the regulated utility to be considered as the number of such installations increases significantly. Under these circumstances, the Companies do not anticipate that it will be necessary for the Commission to regulate CHP systems that are owned by third-party providers and sell the output of their systems only to the on-site customer.

b. No changes to existing statute or rules would be required to effectuate the Companies' position.

CA-SOP-IR-15

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 16, issue 4, paragraph 1.

It is the Consumer Advocate's understanding that MECO has a December 1997 study that analyzed dispersed generation.

a. Please discuss whether each of companies have a similar study evaluated the opportunities and analyzed the feasibility for distributed energy resources of more recent vintage. If so, please provide a copy of those studies.

b. If not specifically discussed, in any studies provided in response to part a. above, please discuss whether there are any circumstances that currently exist where DG could be effectively used on distribution circuits? Please provide copies of maps that show distribution circuits and locations that DG could be sited effectively and the studies or analyses that support the response.

HECO Response:

a. The December 1997 Dispersed Generation Assessment for Maui Electric Company study conducted by RUMLA, Inc. was not updated to consider distributed energy resources of more recent vintage. Currently, HECO, HELCO and MECO transmission and distribution planning divisions evaluate the option of installing distributed generation to resolve transmission and distribution system concerns. More recently, HECO evaluated distributed energy resources for the East Oahu Transmission Project. The report has been filed as Exhibit 6 of Docket No. 03-0417. HELCO has evaluated distributed energy resources for the Waimea-Keamuku (7200) and Waimea-Ouli (7300) 69 kV transmission line overload, however the report is still undergoing an internal review. Provided with this IR response is a portion of the draft report which analyzed CHP and DG options. The attached excerpt from the report is still considered in draft form and the information contained could be changed after further review. As stated in response to CA-SOP-IR-21, MECO is currently in the process of conducting a long-term transmission analysis and will consider CHP resources in its evaluation of options for any transmission system concerns that are identified in the evaluation.

b. The Company assumes that the CA is asking if there are distribution circuits, which require upgrading and which the upgrades could be deferred by the installation of DG. Currently, there are no identified distribution circuits in which upgrades could be deferred by the installation of DG units. However, planning for the distribution system is an ongoing process and the HECO distribution planning process does consider the installation of CHP and DG as an option in its planning process. This process was explained at the April 23, 2004 IRP Advisory Group Technical Committee meeting. Attached is a copy of the presented Distribution Planning Process. HELCO and MECO distribution planning is also an ongoing process and the process will consider distributed generation as a planning options in future analysis.

6.4 INSTALLATION OF UTILITY-SPONSORED CHP ALONG THE KONA COAST OPTION

The results of the sensitivity analysis on the overloads on the 7300 and 7200 lines to the installation of utility-sponsored CHP along the Kona coast are discussed in this section. On October 10, 2003, HELCO filed an application with the PUC for approval of HELCO's CHP program (Docket 03-0336). This program is composed of 3rd party CHP/DG (distributed generation) and utility-sponsored CHP. The MW impacts from the utility-sponsored CHP and 3rd Party CHP programs are forecast on a system-wide basis and therefore are not specific to east or west sides of the HELCO system. The 3rd Party CHP/DG is contained in the load forecast shown in Figure 4-1. The utility-sponsored CHP, which is not part of the load forecast, assumes 9 MW of utility-sponsored CHP by the year 2008, increasing to approximately 23 MW by the year 2024.

As demonstrated in the load flow analysis, the worst loadings on the 7300 and 7200 lines will occur just prior to Keahole commitment. Depending on its location, utility-sponsored CHP can reduce the flows on these 69 kV lines by reducing the load at the customer load buses, which in turn reduces the flow on the 69 kV lines. As discussed previously, the projections for utility-sponsored CHP are on a system-wide basis and are not area specific. Utility-sponsored CHP in the Hilo area will not reduce the flows on either the 7300 or 7200 lines. In fact, utility-sponsored CHP on the east side of the HELCO system will tend to aggravate the overload problem on the 7300 and 7200 lines because some of the power generated by these units will flow on the 7300 and 7200 lines to loads on the west side of the HELCO system. Therefore, the utility-sponsored CHP will have to be located on the west side of the HELCO system, along the Kona coast, in an approximate area from Waika down to Kapua in order to be effective in reducing the overload problems on these lines.

The amount of utility-sponsored CHP required to reduce the loading on the 7300 or 7200 lines to the continuous rating is different in each case due to the fact that the configuration of the 69 kV system is different depending on whether the 7300 line is out-of-service or the 7200 line is out-of-service. Load flow analysis determined that the system configuration with the 7200 line out-of-service is the most severe condition in terms of quantity of utility-sponsored CHP needed to reduce the overload on the 7300 line when compared to the system configuration with the 7300 line out-of-service. Prior load flow results also showed that the worst overload occurs just prior to Keahole generation coming on-line. Under these conditions, and with the 7200 line out-of-service about 20 MW of utility-sponsored CHP on the west side of the HELCO system will be required in order to reduce the overload on the 7300 line to the continuous rating based on current system load conditions. The amount of utility-sponsored CHP needed to reduce the overload on the 7300 line will reduce to 0 MW by the year 2009 assuming the addition of the ST-7 unit at Keahole at that time. The level of utility-sponsored CHP is shown as the small dashed line on Figure 6-4. These results assume economic commitment of HELCO generation.

As the system load increases beyond the pre-Keahole level, Keahole generation will come on-line and tend to reduce the flows on the 7300 and 7200 lines as indicated previously. With utility-sponsored CHP, the situation is slightly different because the utility-sponsored CHP will be committed before Keahole and therefore the utility-sponsored CHP will raise the load level before which Keahole generation comes on-line, in a similar fashion to the situation with as-available generation or the HCPC contract. In order to define an upper limit to the amount of utility-sponsored CHP that will be required to back-off the overload on the 7300 line with the 7200 line out-of-service, the analysis looked at peak conditions with utility-sponsored CHP installed. Load flow studies determined that the amount of utility-sponsored CHP required to reduce the overload on the 7300 line with the 7200 line out-of-service will increase from about 52 MW in the year 2004 to about 59 MW by the year 2007. Under the assumption that the ST-7 unit comes on-line in the year 2009, the amount of utility-sponsored CHP required to reduce the overload on the 7300 line will drop to about 10 MW. The large dashed line on Figure 6-1 shows the upper bound of the amount of utility-sponsored CHP required to maintain the continuous rating on the 7300 line with the 7200 line out-of-service. For this analysis, west Hawaii is assumed to be the next generating plant after ST-7 is installed at Keahole with the first CT starting in the year 2017. The solid line shows the projected amount of utility-sponsored CHP based on HELCO's forecast.

One important result from this analysis is that there will not be sufficient utility-sponsored CHP early enough in time to reduce the overload on the 7300 line as a result of a 7200-line contingency based on current conditions. In addition, since only approximately 23 MW of utility-sponsored CHP is forecast by the year 2024, the projected amount of utility-sponsored CHP will not match the peak load utility-sponsored CHP requirement until the year 2016. At about $1,000/kW, the 20 MW of utility-sponsored CHP will cost approximately $21 million (2004 $), which is about 5 times the cost of reconductoring the two lines 69 kV lines depending on which of the two conductors is selected. At the high end of the required utility-sponsored CHP, 59 MW will cost about $61 million, which is about 13 times the cost of the reconductoring. Therefore, the installation of utility-sponsored CHP as an option to maintain the continuous rating on the 7300 line will cost between $21 and $61 million. There has been no utility-sponsored CHP installed to date because the program is still under consideration by the PUC. Similarly, the foregoing analysis assumes economic generation commitment conditions. Detailed calculations showing the cost of the utility-sponsored CHP for this option are shown in Tables E-2 and E-3 of Appendix E.

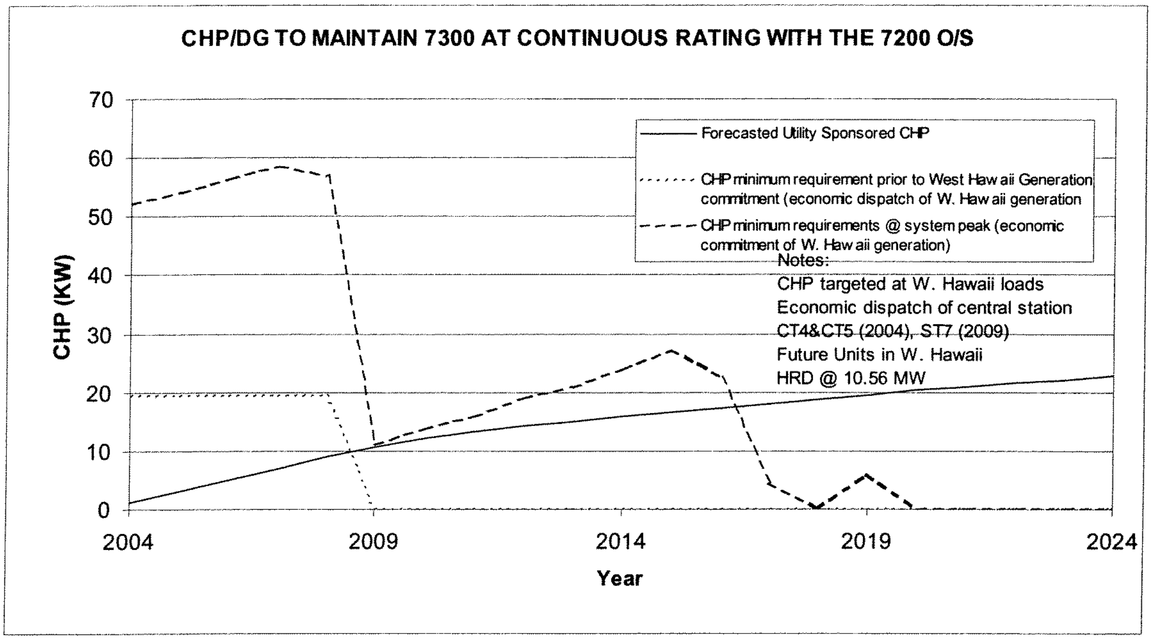


FIGURE 6-4: UTILITY-SPONSORED CHP TO MAINTAIN CONTINUOUS RATING ON 7300 LINE WITH 7200 LINE OUT-OF-SERVICE

6.5 INSTALLATION OF DG UNITS AT HELCO-OWNED SUBSTATIONS ALONG THE KONA COAST OPTION

The sensitivity of the overloads on the 7300 and 7200 lines to the installation of distributed generation (DG) at HELCO-owned substations along the Kona coast is evaluated in this section. In a similar fashion to the utility-sponsored CHP discussed previously, DG units located at HELCO-owned substations in the Hilo area will not be as effective in reducing the flows on either the 7200 or 7300 lines as will units on the west side since the west side units are electrically closed to the loads supplied by the 7300 and 7200 lines. Therefore, the DG units will have to be located on the west side of the HELCO system, along the Kona coast, in an approximate area from Waika down to Kapua in order to be effective in reducing the loading on these lines. These units are assumed to be installed at HELCO-owned substations subject to space availability.

As discussed previously, the worst loadings on the 7300 and 7200 lines will occur just prior to Keahole commitment. The DG units can reduce the flows on these 69 kV lines by reducing the load at the customer load buses, which in turn reduces the flow on the 69 kV lines. As indicated earlier in this discussion, load flow analysis determined that the system configuration with the 7200 line out-of-service is the most severe condition in terms of quantity of utility-sponsored CHP required to reduce the overload on the 7300 line when compared to the system configuration with the 7300 line out-of-service.

Two scenarios are possible with the installation of DG units at HELCO-owned substations along the Kona coast:

1) Assuming the 7200 line is out-of-service for an extended period of up to 5 months for reconductoring, the DG units at HELCO-owned substations will be required to commit with the rest of the generation on the HELCO system in order to reduce the overload on the 7300 or 7200 lines. This scenario is similar to the previous analysis in section 6.4 wherein utility-sponsored CHP units are installed at HELCO-owned substations along the Kona coast also to reduce the overload on the 7300 and 7200 lines. In that analysis, 20 – 59 MW of utility-sponsored CHP is required for the overload conditions. Similarly, 20 – 59 MW of DG generation will be required to cover the period from 2004 – 2024. At about $1,100/kW for a 1 MW DG unit, the 20 - 59 MW of DG units at HELCO-owned substations along the Kona coast will cost about $22.6 – $65.7 million, which is approximately 5 - 15 times the cost of reconductoring the two lines.

2) The second scenario that assumes that the DG units are installed at HELCO-owned substations along the Kona coast and designed to only run if there is a contingency to either one of the 7300 or 7200 lines was considered and rejected. A special protection scheme will be required to detect the tripping of either of the 7300 or 7200 lines. This scheme will then send a signal to the DG units to start and run up to full load using HELCO's Energy Management System (EMS). Based on the results contained in table D-1 of Appendix D, and discussed in section 5.0, HELCO may have as little as about 100 seconds to react to a

contingency involving the 7200 line and initiate a remedial action to reduce the overload. The typical starting time for a 1 MW diesel is about 90 seconds. Therefore, it is unrealistic to assume that 20 or more diesel units could be up and running within 100 seconds.

A separate evaluation determined that as few as 7 or as many as 41 additional containerized 1 MW diesel fuel-based generating units could be installed at HELCO-owned substation sites along the Kona coast subject to space and other requirements being met. Further details on this evaluation are contained in Appendix F. Therefore, sites for a possible additional 15 - 49 1-MW units to make up the total of 59 MW of DG will be required in order to solve the overload problems on the 7300 and 7200 lines to the end of the study period. It appears unrealistic at this point to assume that HELCO will be able to site all these units at HELCO-owned substation sites within the area along the Kona coast.

APPENDIX E

COSTS FOR UNECONOMIC GENERATION OPTION, UTILITY-SPONSORED CHP AND DG OPTIONS

This appendix contains supporting documentation for the costs contained in the main report for the following:

1) Tables E-2 and E-3 contain the cost of adding 59 MW and 20 MW, respectively, of utility-sponsored CHP as discussed in section 6.3. The CHP costs are escalated from a 2003 base of $1000/kW using the GDP Implicit Price Deflator. A discount rate of 8.42 % is used to present value the escalated CHP costs to the year 2004.

2) Tables E-4 and E-5 contain the cost of adding 59 MW and 20 MW, respectively, of DG as discussed in section 6.5. The DG costs are escalated from a 2003 base of $1077/kW using the GDP Implicit Price Deflator. A discount rate of 8.42 % is used to present value the escalated DG costs to the year 2004.

3) Table E-6 contains the cost of adding 22.8 MW of utility-sponsored CHP as discussed in sections 6.3 and 6.8. The CHP costs are escalated from a 2003 base of $1000/kW using the GDP Implicit Price Deflator. A discount rate of 8.42 % is used to present value the escalated CHP costs to the year 2004.

UTILITY-SPONSORED CHP OPTION COSTS

CHP REQUIREMENTS WITH ECONOMIC OPERATION OF CENTRAL STATION UNITS

Year	CHP Installation (MW)	Cost per KW (2003 $/KW)	Escalation	Cost per KW (Current Year $/KW)	Annual Cost (Current Year 000 $)	Dscn Rate (8.42%)	CHP Cost (2004 000 $)
2003		1,000	1.00	1,000			
2004	52	1,000	1.05	1,048	54,489	1.00	54,489
2005	2	1,000	1.07	1,074	2,147	1.08	1,981
2006	2	1,000	1.10	1,101	2,201	1.18	1,873
2007	3	1,000	1.13	1,128	3,385	1.27	2,656
						Total CHP Cost (2004 000 $)	60,999

TABLE E-2: COST OF 59 MW OF UTILITY-SPONSORED CHP BASED ON ECONOMIC DISPATCH WITH KEAHOLE ON-LINE

CHP REQUIREMENTS WITH ECONOMIC OPERATION OF CENTRAL STATION UNITS

Year	CHP Installation (MW)	Cost per KW (2003 $/KW)	Escalation	Cost per KW (Current Year $/KW)	CHP Cost (2004 000 $)
2003		1,000	1.00	1,000	
2004	20	1,000	1.05	1,048	20,957

TABLE E-3: COST OF 20 MW OF UTILITY-SPONSORED CHP BASED ON ECONOMIC DISPATCH WITHOUT KEAHOLE ON-LINE

DG AT HELCO-OWNED SUBSTATIONS OPTION COSTS

DG REQUIREMENTS WITH ECONOMIC OPERATION OF CENTRAL STATION UNITS

Year	DG Installation (MW)	Cost per KW (2003 $/KW)	Escalation	Cost per KW (Current Year $/KW)	Annual Cost (Current Year 000 $)	Dscn Rate (8.42%)	CHP Cost (2004 000 $)
2003		1,077	1.00	1,077			
2004	52	1,077	1.05	1,129	58,685	1.00	58,685
2005	2	1,077	1.07	1,156	2,313	1.08	2,133
2006	2	1,077	1.10	1,185	2,371	1.18	2,017
2007	3	1,077	1.13	1,215	3,646	1.27	2,861
					Total DG Cost (2004 000 $)		65,696

TABLE E-4: DG OPTION COST BASED ON ECONOMIC DISPATCH WITH KEAHOLE ON-LINE

DG REQUIREMENTS WITH ECONOMIC OPERATION OF CENTRAL STATION

Year	DG (MW)	Cost per KW (2003 $/KW)	Escalation	Cost per KW (Current Year)	DG Cost (2004 000)
2003		1,077	1.00	1,077	
2004	20	1,077	1.05	1,129	22,571

TABLE E-5: DG OPTION COST BASED ON ECONOMIC DISPATCH WITHOUT KEAHOLE ON-LINE

FORECASTED UTILITY CHP ADDITION SCHEDULE

Year	CHP Installation (MW)	Cost per KW (2003 $/KW)	Escalation	Cost per KW (Current Year $/KW)	Annual Cost (Current Year 000 $)	8.42% Dscn Rate	CHP Cost (2004 000 $)
2003		1,000	1.00	1,000			
2004	1.2	1,000	1.05	1,048	1,257	1.00	1,257
2005	1.8	1,000	1.07	1,074	1,933	1.08	1,783
2006	2	1,000	1.10	1,101	2,201	1.18	1,873
2007	2	1,000	1.13	1,128	2,257	1.27	1,771
2008	2	1,000	1.16	1,157	2,314	1.38	1,674
2009	1.6	1,000	1.19	1,186	1,898	1.50	1,267
2010	1.6	1,000	1.22	1,216	1,945	1.62	1,198
2011	1.2	1,000	1.25	1,248	1,498	1.76	851
2012	0.9	1,000	1.28	1,281	1,153	1.91	604
2013	0.75	1,000	1.32	1,315	987	2.07	477
2014	0.75	1,000	1.35	1,350	1,013	2.24	451
2015	0.75	1,000	1.39	1,386	1,040	2.43	427
2016	0.75	1,000	1.43	1,430	1,073	2.64	407
2017	0.75	1,000	1.48	1,476	1,107	2.86	387
2018	0.75	1,000	1.52	1,523	1,142	3.10	368
2019	0.75	1,000	1.57	1,572	1,179	3.36	351
2020	0.75	1,000	1.62	1,622	1,216	3.65	334
2021	0.5	1,000	1.67	1,673	837	3.95	212
2022	0.75	1,000	1.73	1,727	1,295	4.29	302
2023	0.5	1,000	1.78	1,782	891	4.65	192
2024	0.75	1,000	1.84	1,838	1,379	5.04	274
					Total CHP Cost (2004 000 $)		16,458

TABLE E-6: FORECASTED UTILITY-SPONSORED CHP COST

APPENDIX F

DG SITE EVALUATION

SITE SELECTION METHODOLOGY FOR DISPERSED GENERATORS (DG) AT HELCO-OWNED SUBSTATION SITES ALONG THE KONA COAST

EXECUTIVE SUMMARY

This evaluation determined that a minimum of 7 and a possible maximum of 41 additional containerized dispersed generating units could be installed at HELCO-owned substation sites along the Kona coast. The largest size unit that can be installed is a 1 MW diesel-fuel based generator.

1.0 INTRODUCTION

The purpose of this evaluation is to determine the potential for installing DG at HELCO-owned substation sites along the Kona coast.

2.0 SCREENING PROCESS

Substation sites are screened for available space based on the single-line drawings, zoning restrictions, permitted noise levels, and accessibility to fuel such as diesel fuel or synthetic natural gas. The results of the screening evaluation are shown in Table F-1.

2.1 ASSUMPTIONS

The following assumptions form the basis of the evaluation of HELCO-owned substation sites for DG installations along the Kona coast:

1) The Kona coast is chosen for the DG installations due to the need to reduce the overload on the 7300 and 7200 69 kV transmission lines supplying the loads along the Kona coast following a single contingency that will overload one of these two lines as discussed previously in the main report. DG installations in other areas such as the east side of the HELCO system will not help reduce the overload problem on the 7300 and 7200 lines and may make the overload problem worse. The area considered for DG installations comprises the west coast of the island of Hawaii from Waika substation in the north down to Punaluu substation near the eastern tip of the island. Punaluu substation is also considered for the DG installations due to the fact that based on load flow studies; the generation of power at the Punaluu site will contribute to the reduction in flows on the 7300 and 7200 lines. The 7300 and 7200 lines supply power to loads along the Kona coast and south past the Keahole power plant. Some of the power supply for the loads tapped off of the 69 kV transmission system south of Keahole comes in part from the PGV and Puna power plants on the east side of the HELCO system via the 6300 69 kV

transmission line. Since Punaluu substation is also tapped to the 6300 line, it is possible to reduce the loading on the 7300 and 7200 lines by adding more generation to this southern 69 kV transmission path at Punaluu. Punaluu is currently the site for one of the four existing dispersed 1 MW DGs on the HELCO system. The DG's will be started up and brought up to full load. By so doing, the power flow on the overloaded 69 kV line will be immediately reduced because the DG's will be supplying a portion of the area load previously supplied by the transmission line.

2) It is assumed that the DG units considered in this analysis will be run on a daily basis prior to a contingency that will overload one of the two of the 69 kV transmission lines in question. This potential operation time will mean the equivalent of more than 300 hours per year. As a result of this proposed mode of operation, the amount of emissions from the DG's may require permitting from the State of Hawaii since it is assumed that the emissions will be more than 100 tons/year. Therefore, these units may not meet Hawaii Administrative Rules (HAR 11-60.1 Subchapter 4) for point source emissions.

3) In order for the generation to be available on a daily basis, it is assumed that a communication link will be needed between the HELCO system dispatch center and the DG location will be needed.

4) It is also assumed that commercially available DG's that are housed in a sound-muffled shipping-type container, approximately 8' x 40', will be used as the basis for screening potential sites for DG installation. A shipping-type container is chosen for housing the DG since the container will allow the DG to be easily transported to the proposed sites. The container will provide protection from the weather for the DG and house the required control and protection facilities.

5) It is assumed that the containers also have a 1000-gallon fuel tank attached, thereby eliminating the need for separate on-site fuel storage.

6) In order to meet the amount of generation required for the 7300 and 7200 69 kV transmission line overload problems discussed in section 5.0 of the main report, the evaluation of DG options assumes units up to 1000 kW kilowatt or 1 MW (megawatt) unit[1] will be used.

The following maximum permissible sound levels are used to determine the acceptability of installing DG along the Kona coast.

ZONING DISTRICTS	DAYTIME PERMISSIBLE NOISE LEVELS – db (A)[2] (7 A.M. – 10 P.M.)
Class A	55

[1] 1000 kW = 1 MW
[2] Title 11, Chapter 46, Hawaii Administrative Rules, Department of Health, Community Noise Control, page 46-7

Class B	60
Class C	70

TABLE F-3: DAYTIME MAXIMUM PERMISSIBLE SOUND LEVELS

The Class A rules apply to lands zoned for residential, conservation, public space, or open space. The Class B rules apply to lands zoned for multi-family dwellings, apartment, business, commercial, hotel, and resort uses. The Class C rules apply to lands zoned for agricultural, country, and industrial uses. Sites are also considered for multiple DG installations if there is sufficient unused space on the site and if permitted noise levels will allow multiple units to be installed. For multiple DG units at a site, the noise level will increase logarithmically. For example, with one unit operating at a site, the operational noise from the unit will be 55 db (A). With a second unit operating at the same time, the noise level will be 58 db (A). Multiple DG units will also mean an increase in exhaust emissions. This DG evaluation did not include an assessment of the potential power system affects such as voltage fluctuations on the local supply facilities when the DG's are connected to power system.

In general, the potential for fuel spillage exists whenever handling liquid fuels. Precautions can be taken to avoid ground contamination due to fuel spillage. The DG's installed on the Hawaii Electric Light Co. (HELCO) system have two double-containment tanks to ensure the integrity of the fuel containers on the DG units. A leak from the inner tank will be contained in the second outer shell. A leak into the outer tank will alarm at the system control center. There are alarms to warn when the fuel level reaches the capacity of the tank, so that there will be no spillage during tank filling. Local spill clean-up equipment is kept at each site in case a spill occurs despite the aforementioned precautions. The units will have two fuel tanks, one holding fuel for a one-day operation, and a second larger tank. Similar precautions will be assumed for the units considered in the following evaluation.

	7300/7200 LINES - AREA SUBSTATIONS	RESULTS OF SCREENING BASED ON AVAILABLE SPACE FROM SINGLE-LINE DRAWINGS	SITE ZONING /DAYTIME PERMITTED NOISE LEVEL db (A)	RESULTS OF SCREENING BASED ON DEED OR LAND USE ORDINANCES	MINIMUM PROPOSED NUMBER OF DG UNITS[3]	MAXIMUM PROPOSED NUMBER OF DG UNITS[2,3,5]
	Anaehoomalu		Ag-1a/70	Deed restricts use to substation only. Site eliminated because DG installation will violate deed covenants..		
	Captain Cook	Site eliminated – No room for DG units.	Ag-1a/70			
	Host Park		Conservation/55	Easement for substation only. Site eliminated due to potential delays in siting DG units		
	Huehue		Ag-5a/70	Site not owned by HELCO. Right of entry is permitted use. Site eliminated due to potential delays in in acquiring site for DG units.		
	Kailua		MG-1a (Industrial)/70		1	6
	Kahaluu		Ag-5a/70	Site eliminated due to concerns with archaeological remains.		
	Kaloko	Site eliminated – No room for DG units.	MG-1a/70			
	Kamaoa		Ag-20a/70	Site not owned by HELCO. Site eliminated due to potential delays in acquiring site for DG units.		
	Kapua		Ag-5a/70	One DG unit already there.	2[1,2]	6[1]
	Keahole Airport		Conservation/55	Site eliminated due to potential delays in siting DG units		
	Kealakehe		Conservation/55	Site eliminated due to potential delays in siting DG units		
	Kealia		Ag-5a/70	Site not owned by HELCO. Site eliminated due to potential delays in acquiring site for DG units.		
	Keauhou	Site eliminated – Limited land area available and below grade site will trap DG exhaust.	Ag-5a/70			
	Kuakini		RM-5/60	.	1	2
	Kawaihae	Site Eliminated - No room for DG units.	RA-.5a/55			
	Keamuku		Ag-20a/70	Additional units may be sited at this site subject to meeting State regulations.	1	6
	Lalamilo		Ag-40a/70	Site eliminated due to potential delays in siting DG at this location based on need for DLNR approval.		
	Mauna Lani		Ag-5a/70	State lease for substation only. Site eliminated due to potential delays in acquiring site for DG units.		
	Ouli		Ag-5a/70	One DG unit already there.	1[1]	4[1]
	Poopoomino		Conservation/55	Easement for substation only. Site eliminated due to potential delays in acquiring site.		
	Punaluu		Ag-20a/70	One DG unit already there.	1[1]	4[1]
	Puuhuluhulu		Ag-1a/70	Easement for substation only. Site eliminated due to potential delays in acquiring site for DG units.		
	Puuwaawaa		Ag-20a/70	Reverts to State if substation use ceases. Site eliminated due to potential delays in siting DG units at this location.		
	South Point		Ag-20a/70		1	6
	Waika (formerly Kohala Ranch)		Ag-3a/7/70		1	4
	Waikoloa		Ag-1a/70	Additional units may be sited at this site subject to meeting State regulations.	1	6
AREA SUBSTATIONS AVAILABLE FOR DG SITING	26	22		9	10[4]	44[4]

2.2 AVAILABLE SPACE

The 26 substation sites along the Kona coast from Waika in the north to Punaluu in the south are screened based on the space available to accommodate an 8' x 40' shipping-type container. The containers will be sited based on a set back of 23 feet from the substation fence in order to comply with the Community Noise Control levels, based on the site zoning, at the property/fence line and taking into account existing substation facilities such as control buildings, switchgear and transformers. The result from this first screening is to remove 4 of the 26 substation sites or about 15% of the candidate substations for DG installation due to lack of space to accommodate an 8' x 40' shipping container together with the existing substation facilities and setback requirements. The substation sites that were eliminated due to lack of space to house a DG unit are shown in Table F-1, column 3.

2.3 DEED RESTRICTIONS, LAND-USE ZONING AND PERMITTED NOISE LEVELS

Installation of generating units is assumed to be a permitted-use at HELCO substation sites along the Kona coast based on a letter entitled "Switching Station and Substation Use Small Mobile Generating Units State Land Use Agricultural District, from Virginia Goldstein, Planning Director, County of Hawaii to Mark Gushiken, Land Administrator, HELCO, dated April 24, 1996. After screening the HELCO substation sites along the Kona coast for available land for possible DG installation, the remaining substations are screened based on the deed restrictions, land use zoning and permitted noise levels based on information from the County of Hawaii, Department of Planning and State of Hawaii.

For several of the substation sites, HELCO only has an easement for its existing substation facilities, meaning that HELCO does not own the land under the substation. Potential negotiations with landowners to purchase the sites currently covered by an easement in order to install DG units at these sites could unnecessarily delay the installation of the DG units. As a result, substation sites that are presently covered by an easement are eliminated from consideration. One site has a restrictive covenant which limits the potential uses of the site to substation purposes only. In a similar fashion, this site is eliminated from consideration as a candidate site for DG installation.

The substation site zoning, among other factors, will determine the permitted noise levels if a DG unit is located on the site. General zoning classifications for the HELCO substations sites considered in this analysis are:

- Agriculture
- Conservation
- Industrial
- Multiple Family
- Residential District

Site zoning and daytime permitted noise level for all sites is shown in column 4. The Department of Land, and Natural Resources (DLNR), State of Hawaii regulates sites zoned as conservation. There are 4 HELCO substation sites that are designated conservation in the area considered for the DG installations. These sites are not considered for DG sites because it is felt that the approval process for siting DG at these sites may potentially delay the program to site DG units along the Kona coast for the transmission overload problem due to the possible need for public hearings.

The site zoning also determines the permitted noise level for DG units installed at substation sites as described in the Assumptions section. The Kawaihae site is the only site under consideration along the Kona coast that is zoned residential district meaning that the permitted noise level at the property line is 55 db (A), the lowest daytime permitted noise level. Since this site is eliminated from consideration due to lack of space to accommodate a DG unit, the residential district zoning will not affect the number of potential DG units that can be installed along the Kona coast. Excluding the conservation-zoned sites, the next highest permitted noise level is 60 db (A) at Kuakini substation, which has a residential multi-family zoning. Based on the existing electrical arrangement of facilities at Kuakini, the installation of 2-1 MW DG units will not exceed the permitted noise level for this site. The remaining substation sites are zoned agricultural with a maximum permitted daytime noise level of 70 db (A). Based on this permitted noise level, up to 6-1 MW DG units are possible subject to obtaining the necessary approvals and available space on the site.

The result from this second screening is to remove 12 of the remaining 22 substation sites or about 46 % of the candidate substations for DG installation. The substation sites that were eliminated based on deed restrictions or land-use designation are shown in Table F-1, column 5.

2.4 FUEL ACCESSIBILITY

Fuel accessibility is an important consideration in the siting of DG units at HELCO substation sites. In contrast to Oahu, SNG is not available on the island of Hawaii, nor is there any underground infrastructure on the island of Hawaii that could be used to bring other fuels such as propane to HELCO-owned substations along the Kona coast. As a result, if the DG units are run on propane, the propane would have to be trucked to the substation sites and stored on-site in special tanks. On-site gas storage tanks will require additional space that may not be available at all substation sites. In a similar fashion, diesel fuel will have to be trucked to the substation sites and stored in the on-board fuel tank attached to the 8' x 40' container. Assuming 70 gal/hour fuel consumption at full load, it is assumed the fuel tanks on the DG units would have to be re-fueled daily based on the plan to run the units to eliminate the overload problems on the 7300 and 7200 lines.

2.5 DG COSTS

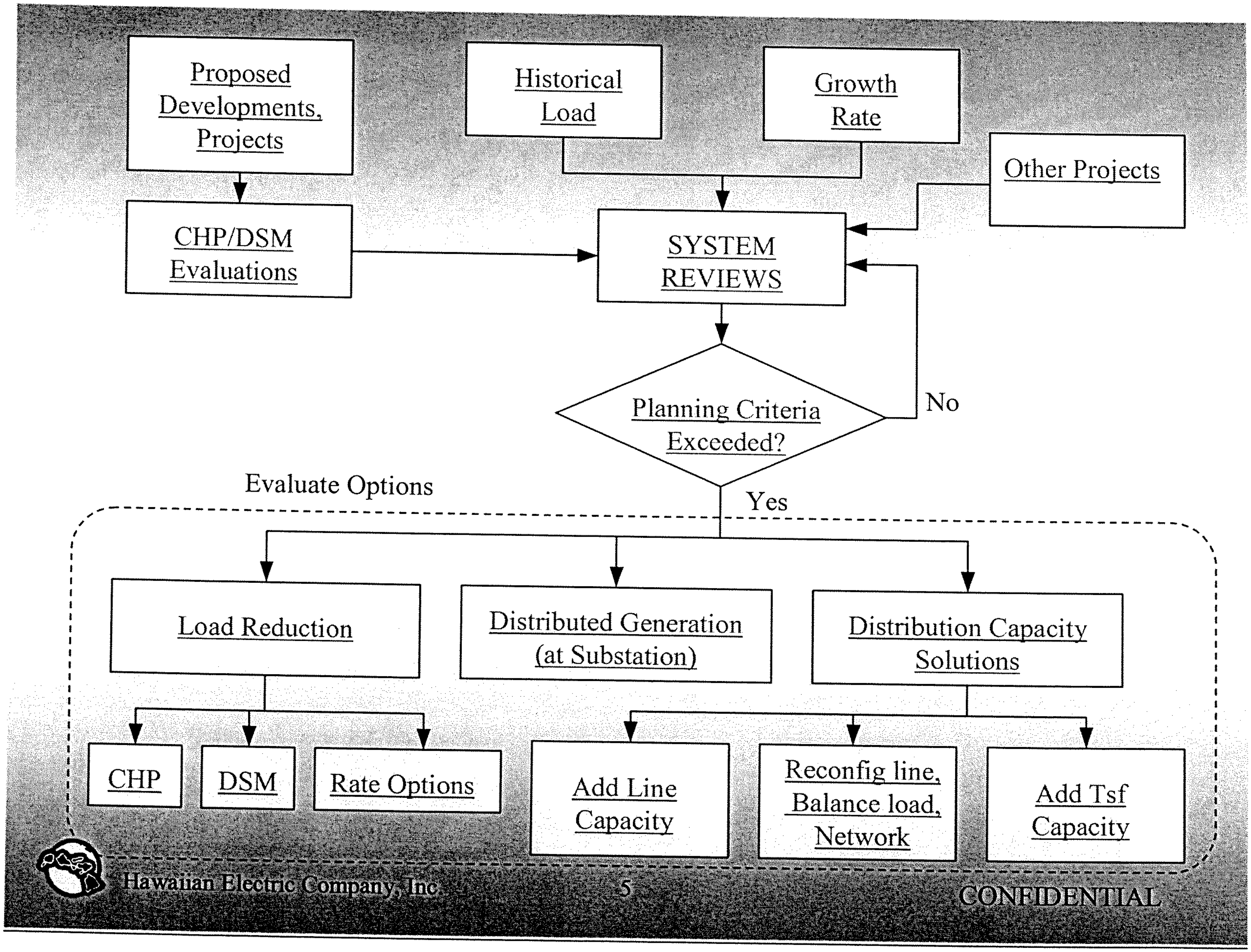
Costs for the diesel-fuel based DG alternatives are based on costs from the HELCO's 1997 Integrated Resource Plan. These costs are shown below.

	$/kW (BASE $)	**$/kW (2004 $)**
Diesel Fuel-BasedGenerator 1 MW (1998$)	$987	$1,128

TABLE F-2: DG COSTS

3.0 RESULTS

Based on this evaluation, 7 – 41 additional containerized generating units can be installed at HELCO-owned substation sites along the Kona coast. The largest size unit that can be installed is a 1 MW diesel fuel-based generator.


Proposed Developments, Projects
CHP/DSM Evaluations
Historical Load
Growth Rate
Other Projects
SYSTEM REVIEWS
Planning Criteria Exceeded?
No
Yes
Evaluate Options
Load Reduction
Distributed Generation (at Substation)
Distribution Capacity Solutions
CHP
DSM
Rate Options
Add Line Capacity
Reconfig line, Balance load, Network
Add Tsf Capacity
Hawaiian Electric Company, Inc.
5
CONFIDENTIAL

CA-SOP-IR-16

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 16, issue 4, paragraph 2, lines 4 and 5.

a. Please give examples of units that were no longer operable or have been replaced and why.

b. Please provide a list of DG that is still operable and discuss the Companies' assessment of why these units are still operable while others are not.

c. What spinning and supplemental generating reserve margins (operating reserves) does the Company use during normal operating conditions?

d. Does the Company believe the DG can supply generation planning reserves and operating reserves? If so, what DG can supply each type of reserve?

HECO Response:

a. The Hess installed units at the University of Nations and at the Hualalei Regency are no longer in service. These were small industrial internal combustion engines that either were poorly maintained or exceeded their normal useful life. The units at Hualalei Regency are being replaced.

b. Please see response to CA-SOP-IR-3 for a list of operating DG units. The Companies have not assessed why these units are still operating (while others are not), and it would be speculative for the Companies to offer such opinions.

c. HECO spinning reserves are based on output of largest running unit and quick load pickup. HELCO and MECO only have operating reserves.

d. The extent to which DGs can provide generation planning reserves[1] and operating reserves[2] will depend on a number of factors, including whether or not the DG is firm and dispatchable by the utility, their operating mode, whether or not they are designed and

---

[1] It is assumed that by "planning reserves" the CA means that amount of firm generating capacity on the system that is available but not is necessarily in operation.

capable of safely exporting power to the grid, operating permit limitations (if any), their power output ramp rates, the extent to which the units can ride through disturbances on the system, and the extent to which the utility can control the maintenance and reliability of the units.

Customer-sited emergency generation theoretically could contribute to a utility's "planning reserve margin" if such generation could be dispatched by the utility to meet its peaking loads, but there are practical difficulties that would have to be addressed. Substation-sited generation could contribute to a utility's "planning reserve margin", and does so in the case of HELCO. See response to HREA-IR-9. Customer-sited DG may impact the load to be served by central station generation (and help to defer the need for central station generation), as is addressed in the Companies' CHP application, but would not contribute to the utility's "planning reserve margin" unless sized in excess of the customer-load, and the excess capacity was available for dispatch by the utility.

The characteristics of small DG units are such that they generally are not suited to provide spinning or operating reserves, since these types of reserves are provided by units that increase or decrease their outputs (i.e., ramp up or down) in response to changes in system frequency (e.g., due to changes in system load, or forced outages of generating units)

DGs in the form of wind turbines, PVs or as-available hydro units would not provide planning reserves or operating reserves. They cannot be counted upon to provide capacity and energy upon demand when needed by the system. Customer-sited DGs in the form of small internal combustion engines that are designed to operate at full load to serve a customer's minimum electrical demand would not be able to provide any planning or

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[2] Operating reserves refers to the amount of dispatchable firm generation that is currently in operation but not is

operating reserve. Fuel cells, which perform optimally in steady-state operation, may not be able to provide operating reserves because they cannot not ramp up quickly in output to meet system needs. In addition, the ramping up and down of a fuel cell could be detrimental to its life and performance.

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serving load and can be called upon to serve load if needed.

CA-SOP-IR-17

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. page 21, issue 6, paragraph 3.

a. Please provide a detailed explanation for the assertion that revenue would be lost because of DG. To support your explanation, please provide copies of any analyses that support the Companies' response.

b. Please identify the estimated order of magnitude for installed DG projects installed by a customer or number of customers that would result in the need to request rate relief. Please provide a copy of any analyses that support the response.

c. If not already provided in response to part b. above, please provide a summary of existing rates and proposed rates (for all affected classes) that would result when relief is sought.

d. Please compare your responses to subparts b. and c. to DG projects that are utility owned. In other words, please discuss whether the threshold of seeking rate relief or impact on rates would vary if the projects were company owned.

HECO Response:

a. [The prior sentence refers to the displacement of "utility generated energy" by customer-sited DG owned by third-parties and customers. Utility revenues for electricity sales are based on kWh of energy and kW of demand. To the extent that either kWh or kW are displaced, revenues would be reduced. No analysis is necessary to demonstrate this self-evident fact.]

There would also be a loss of net revenues (revenues less variable costs saved by not producing the kWh). Due to the manner in which electric rates have been established in Hawaii, the Companies rates for its large commercial customers are not only higher than the Companies marginal costs, but are also higher than its average embedded costs of providing service to such customers. The independent implementation of DG/CHP with the resulting loss of sales revenue would exceed the marginal costs of those lost sales.

The quantification of the incremental revenues from the retained load for the

Companies was provided as part of the economic analysis of the Companies proposed CHP Program, Exhibit H, Docket No. 03-0366, filed on October 10, 2003.

b. HECO has not developed such an estimate. The determination of the need to request rate relief is a complex undertaking, and takes into account many factors in addition to the number of DG/CHP systems installed by third parties.

c. Not applicable.

d. Not applicable.

CA-SOP-IR-18

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. page 22, issue 6.

In this issue, and in issue 10, the Companies make reference to a discount for CHP and the possibility of charging something more than marginal, but less then fully embedded, costs.

a. Please discuss how the Companies envision seeking recovery of the incremental difference between what might be charged and the full retail rates. Please provide a copy of any analyses or other calculations that illustrate the Companies' response.

b. Assuming that, in the future, rates are set to migrate towards cost-based levels, please discuss how the Companies envision seeking recovery of the incremental difference between what might be charged and the fully embedded rates. Please provide a copy of any analyses or other calculations that illustrate the Companies' response.

HECO Response:

a. The Companies are not seeking any cost recovery between rate cases for the difference between the proposed CHP Program energy discount and the rates in the regular rate schedules (i.e., foregone revenues from the proposed Schedule CHP rate discount). The rates in the regular rate schedules would be reset in the Companies next general rate case proceeding, and would take into account the level of CHP systems in operation at that time and related costs and revenues. The Companies have not conducted the requested analyses because the Companies will not be seeking the recovery of the difference between the regular rate schedule rate and the proposed Schedule CHP rates between rate cases.

b. Please see response to part a. above.

CA-SOP-IR-19

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. page 23, issue 7, paragraph 3.

The Company indicates that DG "of all types can reduce transmission line losses, providing additional efficiency improvements."

a. What are the Companies' most recently calculated transmission line losses in kWh and in percent of energy supplied to Customers? Please provide the studies or analyses performed to determine the response. If the most recent analysis available was already provided in a recent rate case, please state so.

b. Please confirm that the most recently filed map of the Companies' transmission systems with the Commission is still current. If not, please provide a copy of each company's map, or, in the alternative, if security and safety concerns apply, please confirm that a copy can be made available for review under protective order.

HECO Response:

a. The most recently calculated transmission line losses in kWh and in percent of energy supplied to the customer for the HECO system is 102,300,000 kWhr or 1.36%. Attached is the workpaper for the calculation, which represents a calculation for the year 2003.

The most recently calculated transmission line losses in kWh and in percent energy supplied to the customer for the Maui system is 12,257,000 kWhr or 1.23%. See page 4 of this IR response. The calculation was provided in MECO's last rate case, Docket 97-0346, MECO-WP-403, page 4. An additional calculation was added to the workpaper in order to determine the losses as a percent of energy supplied to the customer instead of the net-to-system energy.

The most recently calculated transmission line losses in kWh and in percent energy supplied to the customer for the HELCO system is 35,303,000 kWh or 3.77%. See page 5 of this IR response. The calculation was provided in HELCO's last rate case, Docket 99-0207, HELCO-RWP-1950, page 9 submitted on August 25, 2000. An additional calculation was added to the workpaper in order to determine the losses as a percent of energy supplied to the customer instead of the net-to-system energy.

It should be noted that the transmission loss calculation for HECO, MECO and HELCO shown in this IR response isolate the most recent losses calculated for the transmission system. Other loss factors provided in HECO/MECO/HELCO filings may include Company use kWh, unaccounted for kWh that are not billed, auxiliary load losses, different generating unit operating conditions and transmission configurations which would cause the loss percent to be different than what is shown above.

b. It is not known if the maps filed with the Commission are the most current maps for each of the transmission systems. A copy of the most current transmission system maps can be made available for review under a protective order.

Hawaiian Electric Co.
2003 Estimated Energy Losses

		Energy Losses (GWHr)	Percent
A	HECO Gross Gen	4967.0	60.5%
A.1	HECO Aux Load	282.5	3.4%
A.2	HECO GSU Tsf Losses	15.6	0.2%
B	HECO Net Gen	4668.9	56.9%
B.1	IPP Gen Injection	3240.0	39.5%
C.	Delivered To Transmission	7908.9	96.4%
C.1	Trans Losses	86.7	1.1%
C.2	Trans/Sub Tsf Losses	30.8	0.4%
D.	Delivered To Subtrans	7791.4	94.9%
D.1	Subtrans Losses	28.6	0.3%
D.2	Dist Tsf Losses	44.0	0.5%
E.	Delivered To Dist	7718.8	94.1%
E.1	Dist Losses	22.2	0.3%
E.2	Sec Tsf Losses	116.9	1.4%
F.	Delivered To Sec	7579.7	92.4%
F.1	Sec Losses	41.2	0.5%
G.	Delivered To Meter	7538.5	91.9%
H.1	Company Use	16.3	0.2%
H.2	Sales	7522.2	91.7%
J.	Total Losses	386.0	4.7%
K.	System Total	8207.0	

Total Transmission Losses
102.3 Includes items A.2 and C.1
1.36% Percent of transmission losses with respect to Sales
(A.2 + C.1 + C.2)/ G.

Notes:
1) "Total Losses" do not include auxiliary station loads.
2) Percent values are percent of the "System Total."

Table 1.1
Allocation of MECO System Losses
For 1999

		Energy (MWH)	Max Demand (MW)	Min Demand (MW)
A.	Total Generation	1,103,125	178.70	69.80
	IPP Generation	91,043	12.00	8.00
	MECO Gross Generation	1,012,082	166.70	61.80
	MECO Auxiliary Loss	36,111	3.83	2.55
	No Charge	1,680		
B.	Delivered to MECO Generator Step-Up	974,291	162.87	59.25
B.1	MECO Generator Step-Up Loss	3,544	0.72	0.25
	IPP Generation	91,043	12.00	8.00
C.	Delivered to 69/23 kV Transmission	1,061,790	174.15	67.00
C.1	69 kV Transmission Loss	8,713	1.78	0.21
C.2	23 kV Transmission Loss	7,006	1.43	0.51
D.	Delivered to 69/23 kV Distribution Substations	1,046,071	170.94	66.28
D.1	Transformation Loss	6,713	1.37	0.46
E.	Delivered to Distribution Lines	1,039,358	169.57	65.83
E.1	Distribution Line Loss	31,956	6.51	1.68
F.	Delivered to Distribution/Secondary Transformation	1,007,401	163.06	64.15
F.1	Transformation Loss	6,962	1.42	0.91
G.	Delivered to Secondary	1,000,440	161.64	63.24
G.1	Secondary Loss	6,296	1.28	0.21
H.	Delivered to Customer	994,144	160.36	63.03

TOTAL LOSSES (B.1+C.1+C.2+D.1+E.1+F.1+G.1)	71,190
NET-TO-SYSTEM (B.1+ C)	1,065,334
LOSS %	6.68%
Transmission Losses (B.1 + C.1)	12,257
Loss % of Energy delivered to the Customer	1.23%

2000 Base Case - Phase Two HEP Conditions
Allocation of HELCO System Losses
Rebuttal-Revised

		Energy (MWH)	Max Demand (MW)	Min Demand (MW)
A.	Total Generation	1,017,592	169.19	58.50
A.1	IPP Generation	748,288	116.40	24.00
A.2	HELCO Gross Generation	269,304	52.79	34.50
	HELCO Auxiliary Loss	-	0.00	3.48
A.3	No Charge	1,510		
B.	Delivered to HELCO Generator Step-Up	267,794	52.79	31.02
B.1	HELCO Generator Step-Up Loss	1,118	0.24	0.44
B.2	IPP Generation	748,288	116.40	24.00
C.	Delivered to 69 kV Transmission	1,014,964	168.95	54.58
C.1	69 kV Transmission Loss	34,185	7.32	3.64
D.	Delivered to Distribution Substations	980,779	161.63	50.94
D.1	Distribution Transformer Loss	8,772	1.88	0.63
E.	Delivered to Distribution Lines	972,007	159.76	50.31
E.1	Distribution Line Loss	7,832	1.68	0.26
F.	Delivered to Distribution/Secondary Transformation	964,175	158.08	50.05
F.1	Transformation Loss	20,191	4.32	2.09
G.	Delivered to Secondary	943,984	153.76	47.96
G.1	Secondary Loss	8,184	1.75	0.31
H.	Recorded Sales	935,800	152.00	47.65
H.1	Recorded DSM	0		
H.2	Unadjusted Sales	935,800		

TOTAL LOSSES (B.1+C.1+D.1+E.1+F.1+G.1)	80,282
NET-TO-SYSTEM (B.1+C+A.3)	1,017,592
LOSS %	7.889410%
Transmission Losses (B.1 + C.1)	35,303
Loss % of Energy delivered to the Customer	3.77%

CA-SOP-IR-20

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 24, issue 7, paragraph 2, lines 1 and 6

The Companies' seem to indicate that, due to certain factors, DG units may be acceptable as it relates to air emissions.

a. What geographic areas of the Companies' systems would be conducive to DG from an environmental emissions perspective? Please provide a copy of the analyses used to support the response.

HECO Response:

a. In general, locations that have adequate dispersion characteristics are preferable. Dispersion characteristics for emissions are site specific and can be affected by proximity of adjacent structures, terrain features and meteorological conditions. Thus each potential generation site is unique and must be assessed individually from the air permitting perspective unless emissions are so low that a permit is not required. As stated in HECO's preliminary statement of position, there are a number of means to address emission dispersion available such as use of good engineering practice for exhaust ducting, combustion technology, and other emission control techniques.

Analysis of emissions impacts from projects will be conducted during the air permitting process administered by the State Department of Health.

CA-SOP-IR-21

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 25, issue 7, paragraph 2, line 3.

a. If not already provided elsewhere, please identify geographic areas of the Companies' transmission systems that would benefit from DG. Please provide a copy of the analysis or study that supports the response.

b. Please provide the most recent marginal cost of service studies for the transmission and distribution systems.

c. Identify all transmission and distribution delivery system constraints.

d. Please provide transmission and distribution improvement plans to relieve transmission and distribution delivery system constraints. If applicable, please identify the existing docket number for that project, or indicate whether the project appeared on each company's most recent capital budget filed with the Commission.

HECO Response:

a. Information for the Hana DG units was provided in Docket No. 99-0369 (Relocation of Lanai City Units L7 and L8 to Hana Substation) and MECO's IRP-2 Docket No. 99-0004, pages 8-24 and 8-25.

b. Please see HECO Response to COM-SOP-IR-12 for MECO's latest marginal cost study. Please see HECO-1808, HECO-1809, and HECO-1810 in Docket No. 7766 for HECO's latest marginal cost study. Please see HELCO-1807 and HELCO-R-1808 in Docket No. 99-0207 for HELCO's latest marginal cost study.

c. HECO objects to providing this information because the information requested is overly broad and some of the information requested would require a voluminous amount of data. Not withstanding the Company's objection, the response to LOL-SOP-IR-82 provides a list of studies for HECO/HELCO/MECO contains all studies, reports and analysis that the Companies and its subcontractors conducted in the past 10 years with regard to the present transmission lines, subtransmission lines and substations, short-range and long-range transmission planning, consideration of new and/or modified transmission and subtransmission lines and substations, operation and maintenance of these infrastructures (including live-line analysis), for MECO, HECO and HELCO grids.

More recent analysis and constraints on the transmission system can be found as follows:

The HECO system transmission constraints are explained in Docket No. 03-0417, Exhibit 5 and Exhibit 6. Analysis for other areas of the HECO transmission system is dependent on HECO's generation plan, which is currently being reviewed through the HECO IRP-3 process.

The HELCO system constraints have been explained in Docket No. 03-0388 (Kailua Capacitors), the CHP/DG analysis in response to CA-SOP-IR-15 and in Docket No. 97-0349 HELCO's IRP Evaluation Report filed with the Commission on March 31, 2004. Analysis for other areas of the HELCO system is dependent on HELCO's generation plan, which is currently being reviewed through the HELCO IRP-3 process.

The MECO system constraints are currently being analyzed through a long-term transmission study as mentioned in Docket No. 99-0004 MECO's IRP Evaluation Report filed with the Commission on April 30, 2004.

Constraints on the distribution system is an on-going process and distribution projects are currently being reviewed.

d. HECO System:

East Oahu Transmission Project – Docket No. 03-0417

HELCO System:

HELCO 69 kV Low Voltage Situation – Docket No. 03-0388 recently approved by the Commission

7200/7300 Line Overload – Report is being finalized and the projects are included in HELCO's most recently filed 5-year capital budget.

MECO System:

Future projects have not been identified please see the response to section c of this IR.

CA-SOP-IR-22

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 26, issue 8.

The Companies project "that distributed generation will complement, but not replace, central station generation in Hawaii in addressing load growth. The amount of forecasted load growth is much higher than can be met with distributed generation alone, given the relatively small scale of distributed generation systems."

a. Please provide a copy of each company's most recent load growth projections. If the most recent projections have already been provided, please identify the applicable proceeding or filing.

b. In projecting that DG will be complementary to, but not replace, central station generation in Hawaii to address load growth, please discuss the time frame to which this projection is applicable. Please provide a copy of any analyses that support the response.

HECO Response:

a. See the attached pages 3 through 6 for HECO's latest load forecast, pages 7 through 8 for HELCO's latest load forecast, and pages 9 through 11 for MECO's latest load forecast.

b. The statement that DG will be complementary to, but will not replace, central station generation in Hawaii to address load growth applies to the 20-year planning horizon covered by the IRP process. For example, the recorded peak demand in 2003 was 1,242 MW-net. By 2025, the last year of the planning horizon for HECO's IRP-3, peak demand will be an estimated 1,684 MW-net, after deducting the estimated peak reduction benefits from continuation of the existing energy efficiency DSM programs. This is an increase in peak demand of 442 MW.

The total amount of utility and non-utility impacts that were estimated for HECO in the CHP Program application, filed on October 10, 2003 in Docket No. 03-0366, was 43 MW over a 20-year period. This is far short of the amount needed to serve the expected increase in peak demand of 442 MW. Even with the deployment of HECO's proposed residential and commercial & industrial load management programs[1], which are forecasted to reduce the need to provide 41 MW of reserve capacity, 359 MW of additional capacity will be needed. If it is assumed that this amount of capacity would need to be made up by non-heat, electricity-only DG applications, with an average size of 1 MW, more than 390 units would need to be installed based on the need to install more than 1 MW of DG capacity for each 1 MW of demand in order to account for the less than 100% availability of the DG units in aggregate. Given there is only limited experience with the installation of DG units in the State of Hawaii, and that each DG installation would need to undergo the same siting, engineering, permitting, community acceptance and construction process, installing 390 DG units within the 20-year planning horizon would appear to be a major undertaking and well beyond the 90 systems CHP market potential that HECO has forecast (see the revised Exhibit A to the CHP Program application, Docket No. 03-0366, filed December 17, 2003).

[1] HECO filed its application for a Residential Direct Load Control Program on June 6, 2003 in Docket No. 03-0166. HECO filed its application for a Commercial and Industrial Direct Load Control Program on December 11, 2003 in Docket No. 03-0415.

Hawaiian Electric Company, Inc.

2004 - 2024 EVENING PEAK, DAY PEAK, MINIMUM LOAD DEMAND, SALES LOAD FACTOR, AND SALES FORECAST

February 26, 2004

	GROSS MW																GWH SALES				
	Evening Peak						Day Peak					Minimum Load Demand									
	Gross Peak Demand w/o DSM	Acquired DSM Program Impact	Future DSM Program Impact	Gross Peak Demand w/ DSM	% Chg	Sales Load Factor w/ DSM	Gross Peak Demand w/o DSM	Acquired DSM Program Impact	Future DSM Program Impact	Gross Peak Demand w/ DSM	% Chg	Gross Demand w/o DSM	Acquired DSM Program Impact	Future DSM Program Impact	Gross Demand w/ DSM	% Chg	Recorded Sales w/o DSM	Acquired DSM Program Impact	Future DSM Program Impact	Recorded Sales w/ DSM	% Chg
Actual																					
1990	1119				2.7%	66.0%	1093				3.6%	468				1.7%	6470.6				3.5%
1991	1141				2.0%	65.4%	1101				0.7%	470				0.4%	6539.0				1.1%
1992	1173				2.8%	64.5%	1143				3.8%	477				1.5%	6650.4				1.7%
1993	1174				0.1%	64.2%	1145				0.2%	473				-0.8%	6607.4				-0.6%
1994	1193				1.6%	65.0%	1164				1.7%	482				1.9%	6797.4				2.9%
1995	1190				-0.3%	66.8%	1156				-0.7%	487				1.0%	6962.8				2.4%
1996 *	1202	-3		1199	0.8%	67.3%	1210	-1		1209	4.6%	495	0		495	1.6%	7094.7	-3.6		7091.1	1.8%
1997	1227	-7		1220	1.8%	65.9%	1218	-5		1213	0.3%	507	-4		503	1.6%	7068.7	-28.4		7040.3	-0.7%
1998	1187	-12		1175	-3.7%	67.4%	1170	-8		1162	-4.2%	512	-5		507	0.8%	6989.3	-51.0		6938.3	-1.4%
1999	1177	-16		1161	-1.2%	68.8%	1166	-12		1154	-0.7%	526	-3		523	3.2%	7068.2	-70.3		6997.9	0.9%
2000	1223	-20		1203	3.6%	68.2%	1207	-16		1191	3.2%	521	-4		517	-1.1%	7301.6	-89.8		7211.8	3.1%
2001	1257	-24		1233	2.5%	67.4%	1230	-20		1210	1.6%	549	-7		542	4.8%	7389.1	-112.4		7276.7	0.9%
2002	1277	-27		1250	1.4%	67.5%	1250	-23		1227	1.4%	532	-9		523	-3.5%	7524.7	-134.3		7390.4	1.6%
2003	1315	-31		1284	2.7%	66.9%	1280	-24		1256	2.4%	541	-7		534	2.1%	7671.6	-149.4		7522.2	1.8%
Forecast																					
2004	1368	-31	-3	1334	3.9%	65.6%	1322	-25	-3	1294	3.0%	579	-8	0	571	6.9%	7855.9	-159.0	-11.3	7685.6	2.2%
2005	1414	-31	-8	1375	3.1%	65.7%	1368	-25	-6	1337	3.3%	601	-10	0	591	3.5%	8108.0	-158.9	-32.6	7916.5	3.0%
2006	1451	-29	-12	1410	2.5%	65.8%	1414	-26	-11	1377	3.0%	617	-10	0	607	2.7%	8335.4	-156.2	-54.8	8124.4	2.6%
2007	1479	-28	-16	1435	1.8%	65.8%	1442	-24	-15	1403	1.9%	636	-9	0	627	3.3%	8498.9	-147.5	-77.4	8274.0	1.8%
2008	1494	-28	-19	1447	0.8%	65.8%	1456	-24	-20	1412	0.6%	640	-7	0	633	1.0%	8611.3	-145.3	-99.9	8366.1	1.1%
2009	1522	-27	-24	1471	1.7%	65.6%	1483	-24	-25	1434	1.6%	647	-7	0	640	1.1%	8714.9	-142.8	-122.5	8449.6	1.0%
2010	1541	-25	-28	1488	1.2%	65.5%	1504	-24	-27	1453	1.3%	661	-7	0	654	2.2%	8819.7	-135.8	-145.1	8538.8	1.1%
2015	1612	-9	-49	1554	0.9%	65.3%	1567	-9	-47	1511	0.8%	686	-3	0	683	0.9%	9195.6	-46.7	-258.1	8890.8	0.8%
2020	1671	0	-63	1608	0.7%	65.2%	1617	0	-63	1554	0.6%	707	0	0	707	0.7%	9543.5	0.0	-338.5	9205.0	0.7%
2024	1713	0	-63	1650	0.6%	65.1%	1651	0	-63	1588	0.5%	722	0	0	722	0.5%	9771.5	0.0	-338.9	9432.6	0.6%

Forecast evening and day peaks are not reduced for interruptible loads (4 and 5 MW, respectively), but do include standby loads (21 MW and 24 MW, respectively).
Forecast peaks and minimums include impact of HECO and 3rd party CHP.

* Evening peaks are system peaks except for 1996 when day peak was the system peak.

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Hawaiian Electric Company, Inc.

2004 - 2024 EVENING PEAK, DAY PEAK, MINIMUM LOAD DEMAND, SALES LOAD FACTOR, AND SALES FORECAST

February 26, 2004

	GROSS MW															GWH SALES				
	Evening Peak					Day Peak					Minimum Load Demand									
	Gross Peak w/o DSM w/o CHP	HECO CHP Impact	3rd Party CHP Impact	Gross Peak w/o DSM w/ CHP	% Chg	Gross Peak w/o DSM w/o CHP	HECO CHP Impact	3rd Party CHP Impact	Gross Peak w/o DSM w/ CHP	% Chg	Gross Demand w/o DSM w/o CHP	HECO CHP Impact	3rd Party CHP Impact	Gross Demand w/o DSM w/ CHP	% Chg	Recorded Sales w/o DSM w/o CHP	HECO CHP Impact	3rd Party CHP Impact	Recorded Sales w/o DSM w/ CHP	% Chg
Actual																				
1990	1119			1119	2.7%	1093			1093	3.6%	468			468	1.7%	6470.6			6470.6	3.5%
1991	1141			1141	2.0%	1101			1101	0.7%	470			470	0.4%	6539.0			6539.0	1.1%
1992	1173			1173	2.8%	1143			1143	3.8%	477			477	1.5%	6650.4			6650.4	1.7%
1993	1174			1174	0.1%	1145			1145	0.2%	473			473	-0.8%	6607.4			6607.4	-0.6%
1994	1193			1193	1.6%	1164			1164	1.7%	482			482	1.9%	6797.4			6797.4	2.9%
1995	1190			1190	-0.3%	1156			1156	-0.7%	487			487	1.0%	6962.8			6962.8	2.4%
1996 *	1202			1202	1.0%	1210			1210	4.7%	495			495	1.6%	7094.7			7094.7	1.9%
1997	1227			1227	2.1%	1218			1218	0.7%	507			507	2.4%	7068.7			7068.7	-0.4%
1998	1187			1187	-3.3%	1170			1170	-3.9%	512			512	1.0%	6989.3			6989.3	-1.1%
1999	1177			1177	-0.8%	1166			1166	-0.3%	526			526	2.7%	7068.2			7068.2	1.1%
2000	1223			1223	3.9%	1207			1207	3.5%	521			521	-1.0%	7301.6			7301.6	3.3%
2001	1257			1257	2.8%	1230			1230	1.9%	549			549	5.4%	7389.1			7389.1	1.2%
2002	1277			1277	1.6%	1250			1250	1.6%	532			532	-3.1%	7524.7			7524.7	1.8%
2003	1315			1315	3.0%	1280			1280	2.4%	541			541	1.7%	7671.6			7671.6	2.0%
Forecast	Forecast evening and day peaks are not reduced for interruptible loads (4 and 5 MW, respectively), but do include standby loads (21 MW and 24 MW, respectively). Forecast assumes CHP with utility participation.																			
2004	1369	0	0	1368	4.0%	1323	0	0	1322	3.3%	579	0	0	579	7.0%	7860.8	-1.9	-3.0	7855.9	2.4%
2005	1416	-1	-1	1414	3.4%	1370	-1	-1	1368	3.5%	601	0	0	601	3.8%	8118.4	-4.8	-5.6	8108.0	3.2%
2006	1454	-1	-2	1451	2.6%	1417	-1	-2	1414	3.4%	619	-1	-1	617	2.7%	8355.9	-7.5	-13.0	8335.4	2.8%
2007	1484	-2	-3	1479	1.9%	1446	-2	-2	1442	2.0%	639	-1	-2	636	3.1%	8529.0	-11.5	-18.6	8498.9	2.0%
2008	1500	-2	-4	1494	1.0%	1461	-2	-3	1456	1.0%	645	-2	-3	640	0.6%	8653.6	-15.7	-26.6	8611.3	1.3%
2009	1529	-3	-4	1522	1.9%	1490	-3	-4	1483	1.9%	654	-3	-4	647	1.1%	8771.8	-21.4	-35.5	8714.9	1.2%
2010	1549	-3	-5	1541	1.2%	1512	-3	-5	1504	1.4%	669	-3	-5	661	2.2%	8883.7	-24.5	-39.5	8819.7	1.2%
2015	1623	-4	-7	1612	0.9%	1578	-4	-7	1567	0.8%	697	-4	-7	686	0.7%	9288.2	-33.2	-59.4	9195.6	0.8%
2020	1685	-5	-9	1671	0.7%	1631	-5	-9	1617	0.6%	721	-5	-9	707	0.6%	9657.0	-38.5	-75.0	9543.5	0.7%
2024	1728	-5	-10	1713	0.6%	1666	-5	-10	1651	0.5%	737	-5	-10	722	0.5%	9896.1	-41.0	-83.6	9771.5	0.6%

* Evening peaks are system peaks except for 1996 when day peak was the system peak.

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Hawaiian Electric Company, Inc.

2004 - 2024 EVENING PEAK, DAY PEAK, MINIMUM LOAD DEMAND, SALES LOAD FACTOR, AND SALES FORECAST

February 26, 2004

	NET MW											GWH SALES				
	Evening Peak						Day Peak									
	Net Peak Demand w/o DSM	Acquired DSM Program Impact	Future DSM Program Impact	Net Peak Demand w/ DSM	% Chg	Sales Load Factor w/ DSM	Net Peak Demand w/o DSM	Acquired DSM Program Impact	Future DSM Program Impact	Net Peak Demand w/ DSM	% Chg	Recorded Sales w/o DSM	Acquired DSM Program Impact	Future DSM Program Impact	Recorded Sales w/ DSM	% Chg
Actual																
1990																
1991	1088					68.6%	1058					6470.6				3.5%
1992	1129				3.8%	67.1%	1101				4.1%	6539.0				1.1%
1993	1123				-0.5%	67.2%	1099				-0.2%	6650.4				1.7%
1994	1140				1.5%	68.1%	1112				1.2%	6607.4				-0.6%
1995	1158				1.6%	68.6%	1125				1.2%	6797.4				2.9%
1996 *	1159	-2		1157	-0.1%	69.8%	1167	-1		1166	3.6%	6962.8				2.4%
1997	1183	-7		1176	1.6%	68.3%	1174	-4		1170	0.3%	7094.7	-3.6		7091.1	1.8%
1998	1142	-11		1131	-3.8%	70.0%	1128	-7		1121	-4.2%	7068.7	-28.4		7040.3	-0.7%
1999	1135	-15		1120	-1.0%	71.3%	1124	-12		1112	-0.8%	6989.3	-51.0		6938.3	-1.4%
2000	1183	-19		1164	3.9%	70.5%	1165	-15		1150	3.4%	7068.2	-70.3		6997.9	0.9%
2001	1214	-23		1191	2.3%	69.7%	1189	-19		1170	1.7%	7301.6	-89.8		7211.8	3.1%
2002	1230	-26		1204	1.1%	70.1%	1212	-22		1190	1.7%	7389.1	-112.4		7276.7	0.9%
2003	1271	-29		1242	3.2%	69.1%	1237	-23		1214	2.0%	7524.7	-134.3		7390.4	1.6%
												7671.6	-149.4		7522.2	1.8%
Forecast	Forecast evening and day peaks are not reduced for interruptible loads (4 and 5 MW, respectively), but do include standby loads (21 MW and 24 MW, respectively). Forecast peaks and minimums include impact of HECO and 3rd party CHP.															
2004	1322	-29	-3	1290	3.9%	67.8%	1281	-24	-3	1254	3.3%	7855.9	-159.0	-11.3	7685.6	2.2%
2005	1367	-29	-7	1331	3.2%	67.9%	1326	-24	-6	1296	3.3%	8108.0	-158.9	-32.6	7916.5	3.0%
2006	1404	-27	-11	1366	2.6%	67.9%	1369	-24	-10	1335	3.0%	8335.4	-156.2	-54.8	8124.4	2.6%
2007	1432	-26	-15	1391	1.8%	67.9%	1397	-23	-14	1360	1.9%	8498.9	-147.5	-77.4	8274.0	1.8%
2008	1445	-26	-18	1401	0.7%	68.0%	1410	-23	-19	1368	0.6%	8611.3	-145.3	-99.9	8366.1	1.1%
2009	1471	-25	-22	1424	1.6%	67.7%	1436	-23	-23	1390	1.6%	8714.9	-142.8	-122.5	8449.6	1.0%
2010	1493	-24	-26	1443	1.3%	67.6%	1457	-22	-25	1410	1.4%	8819.7	-135.8	-145.1	8538.8	1.1%
2015	1560	-8	-46	1506	0.9%	67.4%	1518	-8	-44	1466	0.8%	9195.6	-46.7	-258.1	8890.8	0.8%
2020	1617	0	-59	1558	0.7%	67.3%	1566	0	-59	1507	0.6%	9543.5	0.0	-338.5	9205.0	0.7%
2024	1658	0	-59	1599	0.7%	67.2%	1600	0	-59	1541	0.6%	9771.5	0.0	-338.9	9432.6	0.6%

* Evening peaks are system peaks except for 1996 when day peak was the system peak.

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Hawaiian Electric Company, Inc.

2004 - 2024 EVENING PEAK, DAY PEAK, MINIMUM LOAD DEMAND, SALES LOAD FACTOR, AND SALES FORECAST

February 26, 2004

	NET MW										GWH SALES				
	Evening Peak					Day Peak									
	Net Peak w/o DSM w/o CHP	HECO CHP Impact	3rd Party CHP Impact	Net Peak w/o DSM w/ CHP	% Chg	Net Peak w/o DSM w/o CHP	HECO CHP Impact	3rd Party CHP Impact	Net Peak w/o DSM w/ CHP	% Chg	Recorded Sales w/o DSM w/o CHP	HECO CHP Impact	3rd Party CHP Impact	Recorded Sales w/o DSM w/ CHP	% Chg
Actual															
1990											6470.6			6470.6	3.5%
1991	1088			1088		1058			1058		6539.0			6539.0	1.1%
1992	1129			1129	3.8%	1101			1101	4.1%	6650.4			6650.4	1.7%
1993	1123			1123	-0.5%	1099			1099	-0.2%	6607.4			6607.4	-0.6%
1994	1140			1140	1.5%	1112			1112	1.2%	6797.4			6797.4	2.9%
1995	1158			1158	1.6%	1125			1125	1.2%	6962.8			6962.8	2.4%
1996 *	1159			1159	0.1%	1167			1167	3.7%	7094.7			7094.7	1.9%
1997	1183			1183	2.1%	1174			1174	0.6%	7068.7			7068.7	-0.4%
1998	1142			1142	-3.5%	1128			1128	-3.9%	6989.3			6989.3	-1.1%
1999	1135			1135	-0.6%	1124			1124	-0.4%	7068.2			7068.2	1.1%
2000	1183			1183	4.2%	1165			1165	3.6%	7301.6			7301.6	3.3%
2001	1214			1214	2.6%	1189			1189	2.1%	7389.1			7389.1	1.2%
2002	1230			1230	1.3%	1212			1212	1.9%	7524.7			7524.7	1.8%
2003	1271			1271	3.3%	1237			1237	2.1%	7671.6			7671.6	2.0%
Forecast	Forecast evening and day peaks are not reduced for interruptible loads (4 and 5 MW, respectively), but do include standby loads (21 MW and 24 MW, respectively). Forecast assumes CHP with utility participation.														
2004	1323	0	0	1322	4.0%	1282	0	0	1281	3.6%	7860.8	-1.9	-3.0	7855.9	2.4%
2005	1369	-1	-1	1367	3.4%	1328	-1	-1	1326	3.5%	8118.4	-4.8	-5.6	8108.0	3.2%
2006	1407	-1	-2	1404	2.7%	1372	-1	-2	1369	3.2%	8355.9	-7.5	-13.0	8335.4	2.8%
2007	1437	-2	-3	1432	2.0%	1401	-2	-2	1397	2.0%	8529.0	-11.5	-18.6	8498.9	2.0%
2008	1451	-2	-4	1445	0.9%	1415	-2	-3	1410	0.9%	8653.6	-15.7	-26.6	8611.3	1.3%
2009	1478	-3	-4	1471	1.8%	1443	-3	-4	1436	1.8%	8771.8	-21.4	-35.5	8714.9	1.2%
2010	1501	-3	-5	1493	1.5%	1465	-3	-5	1457	1.5%	8883.7	-24.5	-39.5	8819.7	1.2%
2015	1571	-4	-7	1560	0.9%	1529	-4	-7	1518	0.8%	9288.2	-33.2	-59.4	9195.6	0.8%
2020	1631	-5	-9	1617	0.7%	1580	-5	-9	1566	0.6%	9657.0	-38.5	-75.0	9543.5	0.7%
2024	1673	-5	-10	1658	0.6%	1615	-5	-10	1600	0.5%	9896.1	-41.0	-83.6	9771.5	0.6%

* Evening peaks are system peaks except for 1996 when day peak was the system peak.

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HAWAII ELECTRIC LIGHT COMPANY, INC.
TABLE 1 (b)

FORECAST OF ANNUAL NET SYSTEM PEAK (MW) AND SALES LOAD FACTOR

May 13, 2003**

	(B) 2001	(B) 2002	(F) 2003	(F) 2004*	(F) 2005	(F) 2006	(F) 2007	(F) 2008*
Base Peak[1]	184.8	189.0	195.1	200.5	206.0	210.3	215.8	222.3
Acquired DSM[2]	(4.2)	(4.6)	(4.6)	(4.6)	(4.6)	(3.4)	(3.4)	(3.4)
Rate Riders[3]	(6.5)	(6.5)	(6.0)	(6.0)	(6.0)	(6.0)	(6.0)	(6.0)
Peak without Future DSM and CHP	174.1	177.9	184.5	189.9	195.4	200.9	206.4	212.9
Future DSM[4]			(0.5)	(0.9)	(1.4)	(1.9)	(2.4)	(2.9)
Peak without CHP Impacts[5]	174.1	177.9	184.0	189.0	194.0	199.0	204.0	210.0
CHP Impacts[6]			(1.1)	(1.7)	(2.7)	(3.4)	(4.0)	(4.5)
Total Net Peak[7]	174.1	177.9	182.9	187.3	191.3	195.6	200.0	205.5
Change in Peak	3.3	3.8	5.0	4.4	4.0	4.3	4.3	5.5
% Change in Peak	1.9%	2.2%	2.8%	2.4%	2.2%	2.2%	2.2%	2.8%
Total Sales (GWH)[8]	962.7	993.2	1,022.2	1,049.4	1,076.6	1,104.6	1,133.8	1,163.3
SLF(%)[9]	63.1%	63.7%	63.8%	63.8%	64.2%	64.5%	64.7%	64.4%

[1] Estimated Base Peak excluding Acquired DSM, Future DSM, Rate Riders, and CHP

[2] Acquired DSM, ramped, at net-to-system level, net of free riders, installations from 1996 through 2002, as revised in the A&S reports (3/31/03)

[3] Estimated Rate Rider Impact at System Peak (Capacity Under Contract (12/02): 6.5MW)

[4] Future DSM, ramped, at net to system level, net of free riders

[5] Net Peak including Acquired DSM, Future DSM, and Rate Riders

[6] Estimated Combined Heat and Power (CHP) impacts at system level, ramped, including both utility and 3rd party installations, and 5.7% T&D loss factor.

[7] Net Peak Including Acquired and Future DSM, Rate Riders, and estimated CHP Impacts

[8] Current 2003 - 2008 Sales Estimates (see Table 1a)

[9] Net Sales Load Factor Values [Sales /(Peak * (Hours/Year))]

* Leap Year

** Sales Forecast amends previous forecast approved by the FPC on February 25, 2003

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HAWAII ELECTRIC LIGHT COMPANY, INC.
TABLE 1 (a)

FORECAST OF CUSTOMER LEVEL SALES (GWH)

May 13, 2003**

	(B) 2001	(B) 2002	(F) 2003	(F) 2004*	(F) 2005	(F) 2006	(F) 2007	(F) 2008*
Base Sales[1]	981.7	1,015.1	1,054.4	1,088.2	1,124.5	1,159.5	1,196.1	1,233.1
Acquired DSM[2]	(19.0)	(21.9)	(23.3)	(23.3)	(23.3)	(20.5)	(19.4)	(19.2)
Sales without Future DSM and CHP	962.7	993.2	1,031.1	1,064.8	1,101.2	1,139.0	1,176.7	1,213.9
Future DSM[3]			(1.4)	(4.0)	(6.7)	(9.4)	(12.2)	(15.1)
Sales without CHP Impacts	174.1	177.9	184.0	189.0	194.0	199.0	204.0	210.0
CHP Impacts[4]			(7.5)	(11.4)	(17.9)	(24.9)	(30.6)	(35.5)
Total Sales	962.7	993.2	1,022.2	1,049.4	1,076.6	1,104.6	1,133.8	1,163.3
Change in Sales	8.5	30.5	29.0	27.2	27.2	28.0	29.2	29.5
% Change	0.9%	3.2%	2.9%	2.7%	2.6%	2.6%	2.6%	2.6%

[1] Estimated Base Sales including Embedded HMEC and excluding Acquired DSM, Future DSM, and CHP

[2] Acquired DSM, ramped, at customer level, net of free riders, installations from 1996 through 2002, as revised in the A&S reports (3/31/03)

[3] Future DSM, ramped, at customer level, net of free riders

[4] Estimate of ramped Combined Heat and Power (CHP) impacts including both utility and 3rd party installations

[5] Sales including Embedded HMEC, Acquired DSM, Future DSM, and CHP

* Leap Year

** Sales Forecast amends previous forecast approved by the FPC on February 25, 2003

Forecast Planning Committee:

Curtis A. Beck

Clyde H. Nagata

Paul Fujioka

Rhea Nakaya

Jay Ignacio

Dan Giovanni

Alan K.C. Hee

forecast_03\S-1 Executive Summary\SIGN_2003_AMENDED.xls

MAUI ELECTRIC COMPANY, LTD.
MAUI DIVISION
2003 - 2008 SALES AND PEAK FORECAST
ADOPTED JUNE 26, 2003
BY THE FORECAST PLANNING COMMITTEE

The Forecast Planning Committee adopts the following 2003-2008 Forecast for Sales, Evening Peak, Day Peak, Minimum Load, and Sales Load Factor:

	MW																GWH SALES				
	Evening Peak (System)						Day Peak					Minimum Load									
	Gross Peak Demand w/o DSM	Acquired DSM Program Impact	Future DSM Program Impact	Gross Peak Demand w/ DSM	% Incr.	Sales Load Factor w/ DSM	Gross Peak Demand w/o DSM	Acquired DSM Program Impact	Future DSM Program Impact	Gross Peak Demand w/ DSM	% Incr.	Gross Demand	Acquired DSM Program Impact	Future DSM Program Impact	Gross Demand	% Incr.	Billed Sales GWH	Acquired DSM Program Impact	Future DSM Program Impact	Sales w/ DSM	% Incr.
Recorded																					
1983	95.4					58.6%	85.9					34.4					490.1				
1984	98.5				3.2%	61.1%	91.0				5.9%	36.6				6.4%	528.4				7.8%
1985	101.9				3.5%	59.7%	95.2				4.6%	33.7				-7.9%	532.6				0.8%
1986	110.1				8.0%	60.6%	102.9				8.1%	38.5				14.2%	584.0				9.7%
1987	118.9				8.0%	59.5%	109.7				6.6%	42.6				10.6%	619.6				6.1%
1988	124.7				4.9%	60.7%	115.1				4.9%	41.7				-2.1%	665.2				7.4%
1989	130.7				4.8%	60.5%	119.4				3.7%	49.7				19.2%	692.8				4.2%
1990	139.8				7.0%	60.3%	127.7				7.0%	49.5				-0.4%	738.6				6.6%
1991	149.1				6.7%	59.5%	135.1				5.8%	55.4				11.9%	777.0				5.2%
1992	159.7				7.1%	59.5%	142.2				5.3%	59.5				7.4%	834.6				7.4%
1993	156.7				-1.9%	62.7%	146.3				2.9%	60.1				1.0%	860.4				3.1%
1994	163.2				4.1%	62.9%	151.5				3.6%	62.0				3.2%	899.3				4.5%
1995	170.7				4.6%	62.5%	159.0				5.0%	66.4				7.1%	933.9				3.8%
1996	175.0	-0.2		174.8	2.4%	63.0%	165.4	0.0		165.4	4.0%	65.6	-0.1		65.5	-1.4%	967.6	-0.3		967.3	3.6%
1997	175.8	-1.1		174.7	-0.1%	63.3%	166.0	-0.5		165.5	0.1%	67.9	0.0		67.9	3.7%	972.8	-4.1		968.7	0.1%
1998	177.9	-1.9		176.0	0.7%	62.8%	168.2	-1.2		167.0	0.9%	70.5	-0.3		70.2	3.4%	975.5	-7.4		968.1	-0.1%
1999	182.5	-2.4		180.1	2.3%	63.2%	169.8	-1.6		168.2	0.7%	74.1	-0.4		73.7	5.0%	1007.1	-10.7		996.3	2.9%
2000	188.4	-3.3		185.1	2.8%	64.0%	175.8	-2.2		173.6	3.2%	74.2	-0.5		73.7	0.0%	1055.2	-14.6		1040.6	4.4%
2001	195.3	-4.3		191.0	3.2%	64.2%	183.2	-2.9		180.3	3.9%	79.7	-0.9		78.8	6.9%	1094.8	-21.3		1073.5	3.2%
2002	199.6	-5.7		193.9	1.5%	64.6%	187.8	-3.7		184.1	2.1%	79.0	-1.2		77.8	-1.3%	1125.8	-29.1		1096.7	2.2%
Forecast																					
2003	206.8	-5.9	-0.7	200.2	3.2%	64.5%	195.7	-3.7	-0.5	191.5	4.0%	81.9	-1.4	0.0	80.5	3.5%	1164.7	-31.1	-3.2	1130.4	3.1%
2004	209.9	-5.9	-1.9	202.1	1.0%	65.4%	198.6	-3.7	-1.2	193.7	1.2%	86.5	-1.4	-0.3	84.8	5.3%	1201.3	-31.1	-9.3	1160.8	2.7%
2005	218.0	-5.9	-3.0	209.1	3.4%	65.1%	206.5	-3.7	-1.9	200.9	3.7%	88.8	-1.4	-0.6	86.8	2.4%	1239.0	-31.1	-15.2	1192.7	2.7%
2006	223.7	-5.9	-4.0	213.8	2.2%	65.1%	212.1	-3.7	-2.6	205.8	2.4%	91.1	-1.4	-0.8	88.9	2.3%	1271.3	-31.1	-20.4	1219.7	2.3%
2007	229.5	-5.5	-5.0	219.0	2.4%	65.1%	217.8	-3.4	-3.4	211.0	2.5%	93.3	-1.4	-1.1	90.8	2.2%	1304.3	-30.4	-25.6	1248.4	2.3%
2008	235.4	-5.5	-6.0	223.9	2.3%	65.3%	223.6	-3.4	-4.1	216.1	2.4%	95.6	-1.3	-1.3	93.0	2.4%	1340.9	-30.0	-30.7	1280.1	2.5%

Notes.
Gross instantaneous peaks and gross integrated minimum are being reported.
Future DSM impacts exclude load management programs and effects of Riders.
Billed sales is reported.
1987 peaks estimated due to meter malfunction.

MAUI ELECTRIC COMPANY, LTD.
LANAI DIVISION
2003 - 2008 SALES AND PEAK FORECAST
ADOPTED JUNE 26, 2003
BY THE FORECAST PLANNING COMMITTEE

The Forecast Planning Committee adopts the following 2003-2008 Forecast for Sales, Evening Peak, Day Peak, Minimum Load, and Sales Load Factor:

	MW																GWH SALES				
	Evening Peak (System)						Day Peak					Minimum Load									
	Gross Peak Demand w/o DSM	Acquired DSM Program Impact	Future DSM Program Impact	Gross Peak Demand w/ DSM	% Incr.	Sales Load Factor	Gross Peak Demand w/o DSM	Acquired DSM Program Impact	Future DSM Program Impact	Gross Peak Demand w/ DSM	% Incr.	Gross Demand	Acquired DSM Program Impact	Future DSM Program Impact	Gross Demand	% Incr.	Billed Sales GWH	Acquired DSM Program Impact	Future DSM Program Impact	Sales w/ DSM	% Incr.
Recorded																					
(a) 1988	2.350					41.0%	2.080										8.471				
1989	2.430				3.4%	56.1%	2.240				7.7%						11.947				41.0%
1990	3.220				32.5%	54.6%	2.850				27.2%						15.398				28.9%
1991	4.500				39.8%	50.3%	4.200				47.4%						19.809				28.6%
1992	4.667				3.7%	55.7%	4.200				0.0%						22.817				15.2%
1993	4.490				-3.8%	60.5%	4.300				2.4%	1.500					23.785				4.2%
1994	4.720				5.1%	63.3%	4.540				5.6%	1.730				15.3%	26.181				10.1%
1995	4.810				1.9%	61.7%	4.390				-3.3%	1.650				-4.6%	25.991				-0.7%
1996	5.020	0.000		5.020	4.4%	60.2%	4.800	0.000		4.800	9.3%	1.748	0.000		1.748	5.9%	26.558	0.000		26.558	2.2%
1997	4.970	-0.020		4.950	-1.4%	60.0%	4.725	-0.015		4.710	-1.9%	1.654	-0.004		1.650	-5.6%	26.075	-0.046		26.029	-2.0%
1998	5.205	-0.055		5.150	4.0%	57.7%	4.641	-0.031		4.610	-2.1%	1.815	-0.005		1.810	9.7%	26.140	-0.091		26.049	0.1%
1999	5.101	-0.061		5.040	-2.1%	59.8%	4.840	-0.040		4.800	4.1%	1.813	-0.013		1.800	-0.6%	26.631	-0.221		26.410	1.4%
2000	5.044	-0.064		4.980	-1.2%	62.0%	4.793	-0.043		4.750	-1.0%	1.937	-0.012		1.925	6.9%	27.360	-0.226		27.134	2.7%
2001	5.215	-0.065		5.150	3.4%	59.9%	4.605	-0.045		4.560	-4.0%	1.885	-0.015		1.870	-2.9%	27.263	-0.234		27.029	-0.4%
2002	4.952	-0.072		4.880	-5.2%	63.2%	4.648	-0.048		4.600	0.9%	1.840	-0.015		1.825	-2.4%	27.272	-0.236		27.036	0.0%
Forecast																					
2003	5.071	-0.072	0.000	4.999	2.4%	63.6%	4.729	-0.048	0.000	4.681	1.8%	1.885	-0.015	0.00	1.870	2.5%	28.095	-0.236	0.000	27.859	3.0%
2004	5.202	-0.072	0.000	5.130	2.6%	62.4%	4.834	-0.048	0.000	4.786	2.2%	1.930	-0.015	0.00	1.915	2.4%	28.356	-0.236	0.000	28.120	0.9%
2005	5.244	-0.072	0.000	5.172	0.8%	62.4%	4.857	-0.048	0.000	4.809	0.5%	1.950	-0.015	0.00	1.935	1.0%	28.495	-0.236	0.000	28.259	0.5%
2006	5.285	-0.072	0.000	5.213	0.8%	62.6%	4.879	-0.048	0.000	4.831	0.5%	1.970	-0.015	0.00	1.955	1.0%	28.818	-0.236	0.000	28.582	1.1%
2007	5.326	-0.072	0.000	5.254	0.8%	62.8%	4.901	-0.048	0.000	4.853	0.5%	1.990	-0.015	0.00	1.975	1.0%	29.146	-0.236	0.000	28.909	1.1%
2008	5.367	-0.072	0.000	5.295	0.8%	63.1%	4.923	-0.048	0.000	4.875	0.5%	2.010	-0.015	0.00	1.995	1.0%	29.526	-0.236	0.000	29.290	1.3%

Notes:
Gross instantaneous peaks and gross integrated minimum are being reported.
(a) From generation data recorded since acquisition in August 1988.

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MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION
2003 - 2008 SALES AND PEAK FORECAST
ADOPTED JUNE 26, 2003
BY THE FORECAST PLANNING COMMITTEE

The Forecast Planning Committee adopts the following 2003-2008 Forecast for Sales, Evening Peak, Day Peak, Minimum Load, and Sales Load Factor:

	MW																	GWH SALES				
	Evening Peak (System)						Day Peak					Minimum Load										
	Gross Peak Demand w/o DSM	Acquired DSM Program Impact	Future DSM Program Impact	Gross Peak Demand w/ DSM	% Incr.	Sales Load Factor	Gross Peak Demand w/o DSM	Acquired DSM Program Impact	Future DSM Program Impact	Gross Peak Demand w/ DSM	% Incr.	Gross Demand	Acquired DSM Program Impact	Future DSM Program Impact	Gross Demand	% Incr.	Billed Sales GWH	Acquired DSM Program Impact	Future DSM Program Impact	Sales w/ DSM	% Incr.
Recorded																					
1984	5.400					51.1%											24.247				
1985	5.250				-2.8%	53.4%											24.545				1.2%
1986	5.250				0.0%	54.9%											25.271				3.0%
1987	5.400				2.9%	53.7%											25.390				0.5%
1988	5.700				5.6%	52.5%											26.262				3.4%
1989	5.650				-0.9%	53.2%											26.323				0.2%
1990	5.900				4.4%	53.5%	4.750					2.150					27.634				5.0%
1991	5.650				-4.2%	57.5%	4.900				3.2%	2.200				2.3%	28.443				2.9%
1992	6.018				6.5%	56.2%	5.024				2.5%	2.150				-2.3%	29.727				4.5%
1993	6.058				0.7%	58.1%	5.200				3.5%	2.302				7.1%	30.843				3.8%
1994	6.350				4.8%	58.8%	5.800				11.5%	2.380				3.4%	32.732				6.1%
1995	7.000				10.2%	55.3%	5.800				0.0%	2.400				0.8%	33.880				3.5%
1996	6.751	-0.001		6.750	-3.6%	58.1%	6.001	-0.001		6.000	3.4%	2.400	0.000		2.400	0.0%	34.483	-0.002		34.481	1.8%
1997	6.648	-0.048		6.600	-2.2%	58.1%	5.979	-0.029		5.950	-0.8%	2.401	-0.001		2.400	0.0%	33.687	-0.101		33.586	-2.6%
1998	6.667	-0.067		6.600	0.0%	60.0%	6.044	-0.044		6.000	0.8%	2.612	-0.012		2.600	8.3%	34.884	-0.212		34.672	3.2%
1999	7.060	-0.110		6.950	5.3%	58.1%	6.272	-0.072		6.200	3.3%	2.673	-0.023		2.650	1.9%	35.683	-0.317		35.366	2.0%
2000	6.641	-0.141		6.500	-6.5%	63.5%	6.292	-0.092		6.200	0.0%	2.777	-0.027		2.750	3.8%	36.829	-0.551		36.278	2.6%
2001	6.603	-0.153		6.450	-0.8%	63.6%	6.000	-0.100		5.900	-4.8%	2.784	-0.034		2.750	0.0%	36.490	-0.557		35.933	-1.0%
2002	6.770	-0.170		6.600	2.3%	60.4%	6.313	-0.113		6.200	5.1%	2.636	-0.036		2.600	-5.5%	35.564	-0.622		34.942	-2.8%
Forecast																					
2003	6.970	-0.170	0.000	6.800	3.0%	60.3%	6.463	-0.113	0.000	6.350	2.4%	2.586	-0.036	0.000	2.550	-1.9%	36.526	-0.622	0.000	35.904	2.8%
2004	7.020	-0.170	0.000	6.850	0.7%	60.4%	6.463	-0.113	0.000	6.350	0.0%	2.636	-0.036	0.000	2.600	2.0%	36.978	-0.622	0.000	36.356	1.3%
2005	7.070	-0.170	0.000	6.900	0.7%	60.7%	6.513	-0.113	0.000	6.400	0.8%	2.636	-0.036	0.000	2.600	0.0%	37.285	-0.622	0.000	36.663	0.8%
2006	7.120	-0.170	0.000	6.950	0.7%	60.7%	6.563	-0.113	0.000	6.450	0.8%	2.636	-0.036	0.000	2.600	0.0%	37.598	-0.622	0.000	36.977	0.9%
2007	7.170	-0.170	0.000	7.000	0.7%	60.8%	6.613	-0.113	0.000	6.500	0.8%	2.636	-0.036	0.000	2.600	0.0%	37.915	-0.622	0.000	37.293	0.9%
2008	7.220	-0.170	0.000	7.050	0.7%	61.1%	6.663	-0.113	0.000	6.550	0.8%	2.636	-0.036	0.000	2.600	0.0%	38.337	-0.622	0.000	37.715	1.1%

Notes:
Gross instantaneous peaks and gross integrated minimum are being reported.

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CA-SOP-IR-23

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 32, issue 10, paragraph 2.

a. Please discuss what costs the service termination charges would cover. Please provide calculations and/or workpapers that illustrate the charge that would be assessed by each company as envisioned by the Companies.

b. Please provide a detailed discussion of how the charges envisioned by the Companies would be administered.

HECO Response:

a. As stated in the Companies' preliminary SOP (p. 32): "While the Companies currently do not intend to propose service termination charges where customers terminate or substantially reduce the level of the electricity supplied by the electric utility (and substitute other options) to address these types of issues, the appropriateness of having service termination charges was raised in the Competition Docket, Docket No. 96-0493." As stated, the Companies currently do not "envision" proposing such service termination charges. The service termination charges "envisioned" in the Competition Docket were identified in the Companies' Final Statement of Position filed October 16, 1998 in Docket No. 96-0493, in Attachment D (pp. 14-15), and in Exhibit 15 to Attachment D (pp. 75-78). In general, the purpose of such a charge is to recover costs incurred by the utility as a result of its obligation to serve, but stranded as a result of a customer's service termination.

b. See response to subpart a.

CA-SOP-IR-24

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Page 36, issue 13, paragraph 1.

a. Did the companies prepare internal transmission and ancillary service rates? If yes, please provide transmission and ancillary service rates for each company with all workpapers.

b. Please provide 2003 system control and load dispatching expense for FERC Account No. 556 (or by the applicable NARUC account).

c. Please provide the following for all the generating units:

   1. Nameplate ratings (MVA).

   2. Nameplate power factor.

   3. Nameplate exciter rating (kW).

   4. Maximum operating capability (MW).

   5. Nameplate reactive capability (MVAr).

d. Please identify all of the generating units that provide load following, spinning reserves and supplemental reserves service.

e. For each of the generating units identified in d. above, please provide the following:

   1. Unit rating (MW).

   2. 2003 fixed operating and maintenance cost.

   3. Unit ramp rate (MW/minute).

f. Please provide the following for each Company's generating units (as of December 31, 2003):

   1. Turbo generation plant in service.

   2. Accessory electric equipment plant in service.

   3. FERC Account 314 plant in service (or the applicable NARUC account).

   4. Rotors, generators and their accessories plant in service.

   5. Exciters and voltage regulators plant in service.

   6. Energy generated (kWh).

g. What were the 12-month coincident peaks in 2003?

h. What were the production and transmission insurance expenses in FERC Account No. 924 (or the applicable NARUC account) in 2003?

i. Please provide the most recent avoided cost calculation for qualifying facilities rate schedule.

<u>HECO Response:</u>

a. No. The Companies did not prepare internal transmission and ancillary service rates.

b. Requested information is not available.

c. Please see the attached table. Some nameplate information is not available.

d. Please see the attached table. It is not clear what the Consumer Advocate means by "supplemental reserves." Please note that MECO and HELCO do not have a spinning reserve policy.

e.

1. Please see the attached table.
2. Requested information is not available.
3. Please see the attached table.

f. Plant in service as of December 31, 2003 is not available. Please see the attached table on available information on energy generated (kWh).

g. The 12-month coincident peaks in 2003 are shown in the following table:

Month	HECO (Net MW)	HELCO (Net MW)	MECO-Maui (Gross MW)	MECO-Lanai (Gross MW)	MECO-Molokai (Gross MW)
Jan-03	1130.0	175.8	188.4	5.08	6.25
Feb-03	1101.0	172.0	182.6	4.82	6.20
Mar-03	1121.0	170.5	187.9	4.74	6.30
Apr-03	1113.0	169.0	183.8	4.62	6.05
May-03	1143.0	165.2	183.3	4.72	6.20
Jun-03	1166.0	164.2	182.4	4.67	5.90
Jul-03	1214.0	168.9	199.7	4.78	6.30
Aug-03	1204.0	175.5	200.6	4.87	6.40
Sep-03	1230.0	176.6	197.9	4.73	6.35
Oct-03	1242.0	183.5	201.7	4.92	6.55
Nov-03	1195.0	183.1	197.5	4.90	6.40
Dec-03	1165.0	186.7	202.0	5.08	6.60

h. The NARUC 92400 accounts for 2003 were as follows:

HECO: $2,355,737

HELCO: $633,206

MECO: $648,490

i. Please see HECO, HELCO and MECO's Avoided Energy Cost Data and 2nd Quarter 2004 Schedule Q Rates filed with the Commission on March 31, 2004.

Unit	Nameplate Rating, MVA	Nameplate Power Factor, %	Nameplate Exciter Rating, kW	Nameplate Operating Capability, MW	Nameplate Reactive Capability, MVAR	Service Capability		Unit Rating, MW-net	Unit Ramp Rate, MW/min	Energy Generated, kWh
						Load Following	Spinning Reserve			
Shaded cells denote calculated values										
HECO Units										
Honolulu 8	62.5	80	170	50	Not available	X	X	52.9	1.4	12,306
Honolulu 9	64	85	170	54.4	Not available	X	X	54.4	1.4	60,504
Kahe 1	96	85	300	81.6	Not available	X	X	88.2	2.3	455,207
Kahe 2	96	85	300	81.6	Not available	X	X	86.3	2.3	448,467
Kahe 3	101	85	Not available	85.85	Not available	X	X	88.2	2.3	462,269
Kahe 4	101	90	Not available	90.9	Not available	X	X	89.2	2.3	496,767
Kahe 5	158.8	85	375	134.98	Not available	X	X	134.7	2.5	805,284
Kahe 6	158.8	85	375	134.98	Not available	X	X	133.9	2.5	724,961
Waiau 3	57.5	87	170	50	Not available	X	X	46.2	0.9	47,192
Waiau 4	57.5	87	170	50	Not available	X	X	46.4	0.5	65,254
Waiau 5	64	85	175	54.4	Not available	X	X	54.6	1.4	96,979
Waiau 6	64	85	175	54.4	Not available	X	X	55.6	1.4	119,156
Waiau 7	96	85	250	81.6	Not available	X	X	88.1	2.3	417,857
Waiau 8	96	85	250	81.6	Not available	X	X	88.1	2.3	440,760
Waiau 9	57	90	Not available	51.3	Not available	X	X	51.9	3.0	
Waiau 10	57	90	Not available	51.3	Not available	X	X	49.9	3.0	
MECO Units										
Maui										
Kahului 1	6.25	80	38	5	3.8	Not available	Not applicable	4.7	Not available	25,500,570
Kahului 2	6.25	80	38	5	3.8	Not available	Not applicable	4.8	Not available	25,915,450
Kahului 3	13.529	85	65	11.5	7.1	Not available	Not applicable	11.0	Not available	85,804,110
Kahului 4	15.625	80	50	13.429	8.0	Not available	Not applicable	11.9	Not available	87,978,590
Maalaea 1	3.250	80	Not available	2.75	Not available	Not available	Not applicable	2.5	Not available	
Maalaea 2	3.250	80	Not available	2.75	Not available	Not available	Not applicable	2.5	Not available	15,030,720
Maalaea 3	3.250	80	Not available	2.75	Not available	Not available	Not applicable	2.5	Not available	
Maalaea 4	7	80	Not available	5.6	Not available	Not available	Not applicable	5.5	Not available	19,100,760
Maalaea 5	7	80	Not available	5.6	Not available	Not available	Not applicable	5.5	Not available	21,030,240
Maalaea 6	7	80	Not available	5.6	Not available	Not available	Not applicable	5.5	Not available	19,343,520
Maalaea 7	7	80	Not available	5.6	Not available	Not available	Not applicable	5.5	Not available	22,716,120
Maalaea 8	7	80	40	5.6	Not available	Not available	Not applicable	5.5	Not available	12,295,080
Maalaea 9	7	80	40	5.6	Not available	Not available	Not applicable	5.5	Not available	2,123,520
Maalaea 10	15.625	80	60	12.5	Not available	Not available	Not applicable	12.3	Not available	69,625,800

Unit	Nameplate Rating, MVA	Nameplate Power Factor, %	Nameplate Exciter Rating, kW	Nameplate Operating Capability, MW	Nameplate Reactive Capability, MVAR	Service Capability		Unit Rating, MW-net	Unit Ramp Rate, MW/min	Energy Generated, kWh
						Load Following	Spinning Reserve			
Shaded cells denote calculated values										
Maalaea 11	15.625	80	60	12.5	Not available	Not available	Not applicable	12.3	Not available	76,084,200
Maalaea 12	15.625	80	60	12.5	Not available	Not available	Not applicable	12.3	Not available	59,972,400
Maalaea 13	15.625	80	60	12.5	Not available	Not available	Not applicable	12.3	Not available	60,618,600
Maalaea 14	29.556	80	Not available	23.64	Not available	Not available	Not applicable	20.8	Not available	169,563,600
Maalaea 15	22.875	80	Not available	18	Not available	Not available	Not applicable	15.2	Not available	111,070,080
Maalaea 16	29.556	80	Not available	23.64	Not available	Not available	Not applicable	20.8	Not available	156,394,800
Maalaea 17	31.25	Not available	Not available	23.84	Not available	Not available	Not applicable	20.8	Not available	40,996,800
Maalaea 19	31.25	Not available	Not available	23.84	Not available	Not available	Not applicable	20.8	Not available	77,335,200
Maalaea X1	3.25	Not available	Not available	2.75	Not available	Not available	Not applicable	2.5	Not available	1,212,000
Maalaea X2	3.25	Not available	Not available	2.75	Not available	Not available	Not applicable	2.5	Not available	2,742,960
Lanai										
Miki Basin LL1	1.250	80	10	1	Not available	Not available	Not applicable	1.0	Not available	89,880
Miki Basin LL2	1.250	80	10	1	Not available	Not available	Not applicable	1.0	Not available	345,310
Miki Basin LL3	1.250	80	10	1	Not available	Not available	Not applicable	1.0	Not available	314,440
Miki Basin LL4	1.250	80	10	1	Not available	Not available	Not applicable	1.0	Not available	228,800
Miki Basin LL5	1.250	80	10	1	Not available	Not available	Not applicable	1.0	Not available	88,480
Miki Basin LL6	1.250	80	10	1	Not available	Not available	Not applicable	1.0	Not available	864,600
Miki Basin LL7	2.750	80	Not available	2.2	Not available	Not available	Not applicable	2.2	Not available	14,269,080
Miki Basin LL8	2.750	80	Not available	2.2	Not available	Not available	Not applicable	2.2	Not available	14,370,720
Molokai										
Palaau P-1	1.563	Not available	Not available	1.25	Not available	Not available	Not applicable	1.3	Not available	567,800
Palaau P-2	1.563	Not available	Not available	1.25	Not available	Not available	Not applicable	1.3	Not available	5,000
Palaau P-3	1.125	Not available	Not available	0.9	Not available	Not available	Not applicable	1.0	Not available	43,000
Palaau P-4	1.125	Not available	Not available	0.9	Not available	Not available	Not applicable	1.0	Not available	248,400
Palaau P-5	1.125	Not available	Not available	0.9	Not available	Not available	Not applicable	1.0	Not available	295,900
Palaau P-6	1.125	Not available	Not available	0.9	Not available	Not available	Not applicable	1.0	Not available	339,400
Palaau P-7	2.750	80	136.7	2.2	Not available	Not available	Not applicable	2.2	Not available	11,198,460
Palaau P-8	2.750	80	136.7	2.2	Not available	Not available	Not applicable	2.2	Not available	13,926,360
Palaau P-9	2.750	80	136.7	2.2	Not available	Not available	Not applicable	2.2	Not available	14,187,600
Palaau CT	3.152	80	Not available	2.5	Not available	Not available	Not applicable	2.2	Not available	83,600
HELCO Units										
Shipman 3	9.375	80	40	7.5	Not available	Not available	Not applicable	7.1	Not available	3,495,945
Shipman 4	9.375	80	Not available	7.5	Not available	Not available	Not applicable	7.3	Not available	4,199,755
Hill 5	17.625	80	75	14.1	Not available	Not available	Not applicable	13.5	Not available	70,869,600

Molokai and Lanai unit ratings are in gross MW

Unit	Nameplate Rating, MVA	Nameplate Power Factor, %	Nameplate Exciter Rating, kW	Nameplate Operating Capability, MW	Nameplate Reactive Capability, MVAR	Service Capability: Load Following	Service Capability: Spinning Reserve	Unit Rating, MW-net	Unit Ramp Rate, MW/min	Energy Generated, kWh
Shaded cells denote calculated values										
Hill 6	27.5	90	Not available	23	Not available	Not available	Not applicable	20.2	Not available	130,538,160
Puna Steam	18.750	80	Not available	15	Not available	Not available	Not applicable	14.1	Not available	76,757,200
Kanoelehua D11	2.685	80	Not available	2.148	Not available	Not available	Not applicable	2.0	Not available	
Waimea D12	3.358	80	35.2	2.686	Not available	Not available	Not applicable	2.8	Not available	7,659,350
Waimea D13	3.358	80	35.2	2.686	Not available	Not available	Not applicable	2.8	Not available	
Waimea D14	3.358	80	35.2	2.686	Not available	Not available	Not applicable	2.8	Not available	
Kanoelehua D15	3.358	80	35.2	2.686	Not available	Not available	Not applicable	2.8	Not available	4,063,640
Kanoelehua D16	3.358	80	35.2	2.686	Not available	Not available	Not applicable	2.8	Not available	
Kanoelehua D17	3.358	80	35.2	2.686	Not available	Not available	Not applicable	2.8	Not available	
Keahole D21	3.358	80	35.2	2.686	Not available	Not available	Not applicable	2.8	Not available	11,999,030
Keahole D22	3.358	80	35.2	2.686	Not available	Not available	Not applicable	2.8	Not available	
Keahole D23	3.125	80	Not available	2.5	Not available	Not available	Not applicable	2.8	Not available	
Panaewa D24	1.563	80	Not available	1.25	Not available	Not available	Not applicable	1.0	Not available	325,960
Ouli D25	1.563	80	Not available	1.25	Not available	Not available	Not applicable	1.0	Not available	
Punaluu D26	1.563	80	Not available	1.25	Not available	Not available	Not applicable	1.0	Not available	
Kapua D27	1.563	80	Not available	1.25	Not available	Not available	Not applicable	1.0	Not available	
Kanoelehua CT1	13.235	85	40	11.25	Not available	Not available	Not applicable	11.5	Not available	749,160
Keahole CT2	23.263	80	102	18.61 @ 90F	Not available	Not available	Not applicable	13.0	Not available	50,216,500
Puna CT3	29.556	80	Not available	23.64	Not available	Not available	Not applicable	20.4	Not available	45,240,960
Keahole CT4	29.556	Not available	Not available	23.64	Not available	Not available	Not applicable	22.1	Not available	0

Calculations Used MVA = MW/P.F.

Note (1) - Per Schedule 5 "Generator Information" of 2003 Form EIA-767 "Steam-Electric Plant Operation and Design Report."
Information is not available on Form EIA-767 for Waiau 9 and Waiau 10 diesel units.

Note (2) - HELCO Energy Generated from HELCO's 2003 Net Generation Report as of December 31, 2004 (Production Department).

December 31, 2003 Plant Balances

Account No.	314	315	344	345
Account Description	Steam - Turbogenerator Unit	Steam - Accessory Electric Equipment	Other Power Production - Turbogenerator Unit	Production - Accessory Electric Equipment
HECO				
Honolulu	13,454,642	2,215,186		
Waiau	33,031,636	8,717,507	5,379,259	2,700,634
Kahe	63,613,092	15,354,698	0	0
	110,099,370	26,287,391	5,379,259	2,700,634
HELCO				
Shipman	2,169,772	1,467,156		
Hill	3,857,543	1,683,924		
Puna	903,465	16,410		
Waimea			600,750	314,614
Kanoelehua			1,134,430	100,955
Gas turbine generators			674,093	526,787
Keahole generators			4,323,746	142,917
Keahole ct2			10,132,355	2,271,652
Puna ct3			12,246,353	2,858,148
Ouli sub dg - generators			457,397	
Panaewa sub dg - generators			434,836	
Kapua sub dg - generators			464,972	
Punaluu sub dg - generators	0	0	457,060	0
	6,930,780	3,167,491	30,925,992	6,215,073
MECO				
Maalaea	5,751,746	2,741,599	99,791,730	18,177,704
Kahului	3,657,943	2,215,326		
Palaau			10,520,597	3,271,894
Miki Basin	0	0	7,788,622	1,965,220
	9,409,689	4,956,925	118,100,949	23,414,818
	126,439,839	34,411,806	154,406,200	32,330,525

CA-SOP-IR-25

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. Pages 35 - 36, issue 13.

a. Other than the Commission's approval of the Companies' proposed CHP program, it does not appear that the Companies have identified any other changes to the existing statutes, state administrative rules, utility rules and practices to facilitate the successful deployment of DG. Please confirm that it is the Companies' assertion that no changes to the statutes, rules and practices are required to successfully deploy DG.

b. The Companies indicate that the process of demonstrating ratepayer benefits should be standardized. Please identify what process of demonstrating ratepayer benefits is being referring to, and discuss the procedures, etc., that should be in a "standardized" process.

<u>HECO Response:</u>

a. The Companies' preliminary position is that no changes are required to Hawaii statutes or to Commission rules.

b. The process of demonstrating ratepayer benefits refers to the quantitative analyses provided in support of the Companies' CHP Application. Justification for CHP system projects should be shown on a programmatic basis, rather than on a project-by-project basis—as long as the terms and conditions under which CHP system services are provided to customers are consistent with the assumptions underlying the quantitative analyses justifying the program.

CA-SOP-IR-26

Ref: HECO, HELCO, and MECO Preliminary SOP, Exhibit A. page 36, issue 13.

The Companies indicate that fuel cost recovery methodologies should be revised to accommodate DT. Please expand on what should be done to revise fuel cost recovery methodologies.

HECO Response:

See the discussion on ECAC Modification in the Companies' CHP Program application, filed on October 10, 2003 in Docket No. 03-0366, Section X (pages 63 through 67) and Exhibit I. See also Workpaper I filed separately on November 13, 2003 in Docket No. 03-0366.